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

FORM 10-K

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

For the fiscal year ended December 31, 2025

or

☐ **TRANSITION REPORT PURSUANT TO 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 No.)**
500 West Texas Ave., Suite 100 Midland, TX	**79701**
(Address of principal executive offices)	**(Zip Code)**

Registrant's 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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2025 was approximately $25.8 billion.

As of February 20, 2026, 282,078,989 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2026 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, 2025

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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.
Argus WTI Houston	Grade of oil that serves as a benchmark price for oil at Houston, Texas.
Argus WTI Midland	Grade of oil that serves as a benchmark price for oil at Midland, Texas.
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.
BO	One barrel of crude oil.
BO/d	One BO per day.
BOE	One barrel of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	One BOE per day.
Brent	A major trading classification of light sweet oil that serves as a benchmark price for oil worldwide.
British Thermal Unit	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 allocated or 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.
Formation	A layer of rock which has distinct characteristics that differ from nearby rock.
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.
Henry Hub	Natural gas gathering point that serves as a benchmark price for natural gas futures on the NYMEX.
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 within a specified interval.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
HSC Hub	Natural gas gathering point that serves as a benchmark price for natural gas at the Houston Ship Channel area.
MBbls	One thousand barrels of crude oil and other liquid hydrocarbons.
MBOE	One thousand BOE, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
MBOE/d	One thousand BOE per day.
Mcf	One thousand cubic feet of natural gas.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	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 mineral acres	The portion of total mineral rights a person or entity owns in a tract of land, calculated by multiplying the gross royalty acres in such tract by such person or entity's fractional ownership interest.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty, overriding interests and other burdens.
Net royalty acres	Net mineral acres multiplied by the average lease royalty interest and other burdens.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Plugging and abandonment	Refers to the sealing off of fluids in the reservoir penetrated by a well so that the fluids from one reservoir will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
Productive well	A well that is found to be mechanically 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 commercially recoverable 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 or PUDs	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.
Standardized measure	The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.
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.
Waha Hub	Natural gas gathering point that serves as a benchmark price for natural gas at western Texas and New Mexico.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
WTI	West Texas Intermediate, a light sweet blend of oil produced from fields in western Texas and is a grade of oil that serves as a benchmark for oil on the NYMEX.
WTI Cushing	Grade of oil that serves as a benchmark price for oil at Cushing, Oklahoma.

GLOSSARY OF CERTAIN OTHER TERMS

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

Adjusted Free Cash Flow	A non-GAAP financial measure calculated as cash flow from operating activities before changes in working capital in excess of cash capital expenditures and further adjusted for the tax impact from divestitures, merger and transaction expenses, costs of early terminations of derivatives and settlements of any treasury locks.
April 2024 Notes	The outstanding senior notes issued by Diamondback Energy, Inc. under indentures where Diamondback E&P is the sole guarantor, consisting of the 5.200% Senior Notes due 2027, 5.150% Senior Notes due 2030, 5.400% Senior Notes due 2034, 5.750% Senior Notes due 2054 and 5.900% Senior Notes due 2064.
ASU	Accounting Standards Update.
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
Diamondback E&P	Diamondback E&P LLC, a Delaware limited liability company and a wholly owned subsidiary of the Company.
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173).
Endeavor Acquisition	The acquisition of Endeavor Parent, LLC.
EPA	United States Environmental Protection Agency.
Equity Plan	The Company’s 2021 Amended and Restated 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.
Nasdaq	The Nasdaq Global Select Market.
NYMEX	New York Mercantile Exchange.
OPEC	Organization of the Petroleum Exporting Countries.
OSHA	Federal Occupational Safety and Health Act.
Rattler	Rattler Midstream LP, a Delaware limited partnership and a wholly owned subsidiary of the Company since 2022.
Rattler LLC	Rattler Midstream Operating LLC, a Delaware limited liability company and a wholly owned subsidiary of the Company since 2022.
Ryder Scott	Ryder Scott Company, L.P.
SEC	United States Securities and Exchange Commission.
SEC Prices	Unweighted arithmetic average of the first-day-of-the-month price for each month during the 12-month period prior to the ending date of the period covered by this report.
Securities Act	The Securities Act of 1933, as amended.
Tranche A Loans	The term loan credit agreement with Diamondback Energy, Inc., as guarantor, with Diamondback E&P, as borrower, and Citibank, N.A., as administrative agent.
Guaranteed Senior Notes	The outstanding senior notes issued by Diamondback Energy, Inc. under indentures where Diamondback E&P is the sole guarantor, consisting of the April 2024 Notes, 3.250% Senior Notes due 2026, 3.500% Senior Notes due 2029, 3.125% Senior Notes due 2031, 6.250% Senior Notes due 2033, 5.550% Senior Notes due 2035, 4.400% Senior Notes due 2051, 4.250% Senior Notes due 2052, and 6.250% Senior Notes due 2053.
SOFR	The secured overnight financing rate.
TSR	Total stockholder return of the Company’s common stock.
Viper	(i) New Viper following the Sitio Acquisition, (ii) Former Viper prior to the Sitio Acquisition but after the Viper Conversion, and (iii) Viper Energy Partners LP prior to the Viper Conversion (each term as defined in Note 1—Description of the Business and Basis of Presentation in Item 8. Financial Statements and Supplementary Data of this report).
Viper LLC	Prior to December 23, 2025, Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of Viper Energy, Inc. and after December 23, 2025, VNOM Holding Company LLC, a Delaware limited liability company and a consolidated subsidiary of Viper Energy, Inc.
Viper Notes	The senior notes issued by Viper Energy, Inc. under indentures where Viper Energy Partners, LLC and other subsidiaries were guarantors, consisting of the 5.375% Senior Notes due 2027 and the 7.375% Senior Notes due 2031, and which were redeemed on November 1, 2025 and July 23, 2025, respectively.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act, which involve risks, uncertainties and assumptions. All statements, other than statements of historical fact, including statements regarding our: future performance; business strategy; future operations (including drilling plans and capital plans); estimates and projections of revenues, losses, costs, expenses, returns, cash flow, and financial position; reserve estimates and our ability to replace or increase reserves; anticipated benefits or other effects of strategic transactions (including the recently completed Double Eagle Acquisition and Viper’s Sitio Acquisition (in each case, as defined below) discussed in this report and other acquisitions or divestitures); and plans and objectives of management (including plans for future cash flow from operations and for executing environmental strategies) are forward-looking statements. When used in this report, the words “aim,” “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecast,” “future,” “guidance,” “intend,” “may,” “model,” “outlook,” “plan,” “positioned,” “potential,” “predict,” “project,” “seek,” “should,” “target,” “will,” “would,” and similar expressions (including the negative of such terms) as they relate to the Company are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Although we believe that the expectations and assumptions reflected in our forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond our control. Accordingly, forward-looking statements are not guarantees of future performance and our actual outcomes could differ materially from what we have expressed in our forward-looking statements.

Factors that could cause our outcomes to differ materially include (but are not limited to) the following:

- geopolitics and market conditions, including changes in supply and demand levels for oil, natural gas, and natural gas liquids, and the resulting impact on the price for those commodities;
- changes in U.S. energy, environmental, monetary and trade policies, including with respect to tariffs or other trade barriers and any resulting trade tensions;
- actions taken by the members of OPEC and its non-OPEC allies (“OPEC+”) affecting the production and pricing of oil, as well as other domestic and global political, economic, or diplomatic developments;
- changes in general economic, business or industry conditions, including changes in foreign currency exchange rates, interest rates, inflation rates and instability in the financial sector;
- regional supply and demand factors, including delays, curtailment delays or interruptions of production, or governmental orders, rules or regulations that impose production limits;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including the effect of existing and future laws and governmental regulations;
- physical and transition risks relating to climate change, changing political and social perspectives on climate change and other ESG (as defined below) factors, and risks from our publicly disclosed targets related to sustainability and emissions reduction initiatives;
- challenges in developing our existing leasehold acreage and finding, developing or acquiring additional reserves;
- restrictions on the use of water, including limits on the use of produced water and a moratorium on new produced water disposal well permits recently imposed by the Texas Railroad Commission in an effort to control induced seismicity in the Permian Basin;
- significant declines in prices for oil, natural gas, or natural gas liquids, which could require recognition of significant impairment charges;
- conditions in the capital, financial and credit markets, including the availability and pricing of capital for acquisitions, exploration and development operations;
- challenges with employee retention and an increasingly competitive labor market;
- changes in availability or cost of rigs, equipment, raw materials, supplies and oilfield services;
- changes in safety, health, environmental, tax, and other regulations or requirements (including those addressing air emissions, water management, or the impact of global climate change);
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, or from breaches of information technology systems of third parties with whom we transact business;

- lack of, or disruption in, access to adequate and reliable electrical power, internet and telecommunication infrastructure, information and computer systems, transportation, processing, storage and other facilities for our oil, natural gas, and natural gas liquids;
- failures or delays in achieving expected reserve or production levels from existing and future oil and natural gas developments, including due to operating hazards, drilling risks, or the inherent uncertainties in predicting reserve and reservoir performance;
- inability to keep pace with technological developments in our industry;
- failure to meet our obligations under our oil purchase contracts;
- loss of one or more customers or their inability to meet their obligations;
- geographical concentration of our primary operations;
- risks from our return of capital commitment, and uncertainties over our future dividends and share repurchases;
- difficulty in obtaining necessary approvals and permits;
- severe weather conditions and natural disasters;
- changes in the financial strength of counterparties to our credit facilities and hedging contracts;
- our substantial indebtedness and restrictions to our operating and financial flexibility;
- changes in our credit rating;
- failure to identify, complete and successfully integrate acquisitions, including the recently completed Double Eagle Acquisition and Viper’s Sitio Acquisition (each as defined below);
- the Endeavor equityholders’ ability to significantly influence our business and potential conflicts of interest; and
- other risks and factors discussed in this report.

In light of these factors, the events anticipated by our forward-looking statements may not occur at the time anticipated or at all. Moreover, we operate in a very competitive and rapidly changing environment and new risks emerge from time to time. We cannot 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 anticipated by any forward-looking statements we may make. Accordingly, you should not place undue reliance on any forward-looking statements made 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 applicable law.

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 primarily 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 one reportable segment, the upstream segment.

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, 2025, our total acreage position in the Permian Basin was approximately 1,097,846 gross (869,036 net) acres, which consisted primarily of 982,692 gross (774,645 net) acres in the Midland Basin and 115,154 gross (94,391 net) acres in the Delaware Basin.

In addition, our publicly traded subsidiary, Viper, owns mineral interests primarily in the Permian Basin. At December 31, 2025, we owned approximately 42% of Viper's outstanding shares of common stock on a fully diluted basis, after giving effect to the outstanding TWR Class B Option (as defined and discussed in Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report).

As of December 31, 2025, our estimated proved oil and natural gas reserves were 3,617,856 MBOE (which includes estimated reserves of 406,035 MBOE attributable to the mineral interests owned by Viper). As of December 31, 2025, approximately 70% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 1,351 gross (1,244 net) horizontal well locations in which we have a working interest. As of December 31, 2025, our estimated proved reserves were approximately 49% oil, 24% natural gas and 27% natural gas liquids.

Significant Acquisitions and Divestitures

Diamondback Acquisitions and Divestitures

2025 Drop Down

On May 1, 2025, our wholly owned subsidiary Endeavor Energy Resources, LP ("EER LP") divested all of the issued and outstanding equity interests in 1979 Royalties, LP and 1979 Royalties GP, LLC (collectively, the "Endeavor Subsidiaries") to Viper and Viper LLC in exchange for consideration consisting of (i) $873 million in cash including customary post-closing adjustments, and (ii) the issuance of 69.63 million Viper LLC units and an equal number of shares of Viper's Class B common stock (the "2025 Drop Down").

Double Eagle Acquisition

On April 1, 2025, we completed our acquisition of all of the issued and outstanding interests of DE Permian, LLC, DE IV Combo, LLC and DE IV Operating, LLC, each of which were wholly owned subsidiaries of Double Eagle IV Midco, LLC (the "Double Eagle Acquisition") for consideration of $3.1 billion in cash and approximately 6.84 million shares of the Company's common stock, including transaction costs and subject to certain customary post-closing adjustments. The Double Eagle Acquisition consists of approximately 67,700 gross (40,000 net) acres, which are primarily located in the Midland Basin, and approximately 407 gross (342 net) horizontal locations in primary development targets. We funded the cash portion of the Double Eagle Acquisition through a combination of proceeds from the 2035 Notes (as defined and discussed in Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report), proceeds from the 2025 Term Loan (as defined and discussed in Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report) and borrowings under our credit facility.

Non-Core Asset Divestitures

During the year ended December 31, 2025, we divested approximately $1.7 billion in non-core assets, including our 27.5% equity interest in EPIC Crude Holdings, LP (“EPIC”) and our subsidiary, Environmental Disposal Systems, LLC, (“EDS”) which operated water assets acquired in the Endeavor Acquisition as discussed in Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report.

Viper Transactions

Divestiture of Non-Permian Assets

On February 9, 2026, Viper divested all of its non-Permian assets, including those acquired from Sitio Royalties Corp. (“Sitio”), to an affiliate of GRP Energy Capital LLC and Warwick Capital Partners LLP for net cash proceeds of approximately $617 million, subject to customary post-closing adjustments (the “Viper Non-Permian Divestiture”). The divested properties consisted of approximately 9,400 net royalty acres in the Denver-Julesburg, Eagle Ford and Williston basins with current production of approximately 4,750 BO/d.

Sitio Acquisition

On August 19, 2025, Viper and Viper LLC completed a series of transactions in which Viper Energy, Inc. (formerly known as New Cobra Pubco, Inc., “New Viper”) acquired Sitio, Sitio Royalties Operating Partnership, LP (“Sitio OpCo”) and their respective subsidiaries, pursuant to the Agreement and Plan of Merger, dated June 2, 2025, by and among VNOM Sub, Inc. (formerly known as Viper Energy Inc., “Former Viper”), Viper LLC, Sitio, Sitio OpCo, New Viper, Cobra Merger Sub, Inc. and Scorpion Merger Sub, Inc. (the “Sitio Acquisition”). The Sitio Acquisition was an all-equity transaction valued at approximately $4.0 billion, including customary transaction costs and post-closing adjustments and the partial retirement of Sitio’s net debt of approximately $1.2 billion. The mineral and royalty interests acquired in the Sitio Acquisition represent approximately 25,300 net royalty acres in the Permian Basin and approximately 9,000 net royalty acres in the Denver-Julesburg, Eagle Ford and Williston basins, for total acreage of approximately 34,300 net royalty acres.

See Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report for additional discussion of our acquisitions and divestitures during 2025.

Our Business Strategy

Our business strategy includes the following:

- **Exercise capital discipline.** During 2025, we continued building on our execution track record, generating free cash flow while keeping capital costs under control. Our efficiency gains, particularly in the Midland Basin drilling and completion programs, enabled us to mitigate certain inflationary pressures on variable well costs, which led to a total cash capital expenditure amount of $3.5 billion, consistent with our guidance presented in November 2025. We expect to continue to exercise capital discipline, with a focus on capital efficiency over volume growth and plan to spend between $3.60 billion and $3.90 billion in cash capital expenditures in 2026.

- **Focus on low cost development and continuous operational improvement.** 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 97% of our acreage, which allows us to efficiently manage our operating costs, pace of development activities and the gathering and marketing of our production. Our average 79% working interest in our acreage allows us to realize the majority of the benefits of these activities and cost efficiencies.

- **Continue to deliver on our capital return program.** We expect to be in a position to continue to deliver on our capital return program, through which we intend to return at least 50% of our quarterly Adjusted Free Cash Flow to our stockholders. Our capital return program is currently focused on a sustainable and growing base dividend and opportunistic stock repurchases. The remainder of our Adjusted Free Cash Flow will be used primarily to reduce debt.

- **Leverage our experience operating in the Permian Basin.** Our executive team, which has significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by optimizing 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 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 top operators in the area in an effort to benchmark our performance and adopt best practices compared to our peers. The successful execution of the Endeavor Acquisition and the Double Eagle Acquisition have further strengthened our existing operating experience and delivered certain operational synergies ahead of schedule.

- **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. We believe our executive team, with its extensive experience in the Permian Basin, has a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets, as evidenced by the Endeavor and Double Eagle acquisitions.

- **Maintain financial flexibility.** We seek to maintain a conservative financial position. As of December 31, 2025, Diamondback had $91 million of standalone cash and cash equivalents and our borrowing base was set at $2.5 billion, which was fully available for future borrowings. As of December 31, 2025, Viper had $13 million of cash and cash equivalents, $105 million in outstanding borrowings and approximately $1.4 billion available for future borrowings under its revolving credit facility. Additionally, we have a target of reducing our net debt (which we define as total debt, excluding debt issuance costs, discounts, premiums and unamortized basis adjustments, less cash and cash equivalents) to $10.0 billion. In 2025, we exceeded our previously announced commitment to sell at least $1.5 billion of our non-core assets, and accelerated debt reduction with the proceeds to help maintain a strong balance sheet.

- **Deliver on our commitment to environmental, social and governance (“ESG”) performance**. We are committed to the safe and responsible development of our resources in the Permian Basin. Our approach to ESG is evidenced through our commitment to people, safety, environmental responsibility, community and sound governance practices.

Our Strengths

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

- **Oil rich resource base in one of North America’s leading resource plays.** Substantially 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.

- **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 economic price of approximately $50.00 per Bbl WTI, we currently have approximately 8,854 gross (6,541 net) identified 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 10,924 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 at these locations may vary due to different factors, which would result in a higher or lower location count. In addition, we have approximately 17,498 square miles of licensed 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. We further enhanced our multi-year inventory through the Endeavor Acquisition and the Double Eagle Acquisition.

- **Experienced, incentivized and proven management team.** Our executive team has a proven track record of executing on large-scale development drilling programs and extensive experience in the Permian Basin. Our executive team has significant experience with both drilling and completing horizontal wells in addition to horizontal well reservoir and geologic expertise.

- **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 stable and predictable and that we are faced with less operational risks in the Permian Basin when compared to other emerging hydrocarbon basins.

- **High degree of operational control.** We are the operator of approximately 97% 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. We retain the ability to increase or decrease our capital expenditure program based on commodity price outlooks.

Our Properties

Location and Land

The Permian Basin 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, 2025, our total acreage position in the Permian Basin was approximately 1,097,846 gross (869,036 net) acres, which consisted primarily of 982,692 gross (774,645 net) acres in the Midland Basin and 115,154 gross (94,391 net) acres in the Delaware Basin. In addition, as of December 31, 2025, Viper owned mineral interests underlying approximately 1,986,216 gross (36,004 net) royalty acres in the Delaware Basin and approximately 1,891,742 gross (50,595 net) royalty acres in the Midland Basin. Approximately 35% of these net royalty acres are operated by us.

We have been developing multiple pay intervals primarily 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 as of December 31, 2025:

Basin:	**Number of Horizontal Wells**
Midland	6,105
Delaware	528
Other	44
Total[(1)]	6,677

(1) Of these 6,677 total horizontal producing wells, we are the operator of 5,342 wells and have a non-operated working interest in 1,335 additional wells.

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, Barnett and Woodford 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, 2025, we held working interests in 11,750 gross (9,642 net) producing wells and only royalty interests in 43,912 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 commingling 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 led to deposits of organically rich mudstone such as the Devonian Woodford and Mississippian Barnett. 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, Barnett and Woodford 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 17,498 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.

Recent and Future Activity

We currently estimate that our cash capital expenditures in 2026 will be between $3.60 billion and $3.90 billion, including $3.05 billion to $3.27 billion for operated horizontal drilling and completions. During the year ended December 31, 2025, we drilled 463 gross (430 net) and completed 503 gross (476 net) operated horizontal wells and incurred capital expenditures for drilling, completing and equipping wells, infrastructure and midstream additions to oil and natural gas properties of $3.5 billion.

We were operating 15 drilling rigs and four completion crews at December 31, 2025 and currently intend to operate between 15 and 18 rigs and approximately five completion crews on average in 2026. 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.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

The estimated reserves as of December 31, 2025, 2024 and 2023 are based on reserve estimates prepared by our internal reservoir engineers and audited by Ryder Scott, an independent petroleum engineering firm. The internal and external technical persons responsible for preparing or auditing 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.

The purpose of Ryder Scott's audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates and covered 100% of our total proved reserves for 2025, 2024 and 2023.

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, 2025 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: (i) performance-based methods, (ii) volumetric-based methods, and (iii) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. In general, our 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 data. In certain cases where there was inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate, the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there was 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 undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, we 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 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 included, but were not limited to, production, downhole completion information, geologic 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 and Item 7. Management's Discussion and Analysis—Critical Accounting Estimates of this report. As a result, we maintain an internal staff of petroleum engineers and geoscience professionals that have an internal control process to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical staff met with our independent reserve auditor periodically during their January 13, 2026 audit of the December 31, 2025 reserve reports to discuss the assumptions and methods used in our proved reserve estimation process. As part of the audit process, we provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and natural gas production, commodity prices and operating and development costs.

The Executive Vice President and Chief Engineer is primarily responsible for overseeing the preparation of all our reserve estimates and overseeing communications with our independent reserve auditor. The Executive Vice President and Chief Engineer is a petroleum engineer with over 22 years of reservoir and operations experience and our geoscience staff has an average of approximately 17 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and natural gas production, commodity prices and operating and development costs. Ryder Scott performed an independent analysis during its audit of our estimated reserves for 2025 and any differences were reviewed with our Executive Vice President and Chief Engineer. For 2025, our reserve auditor's estimates of our proved reserves did not materially differ from our estimates by more than the established audit tolerance guidelines of ten percent.

The internal control procedures utilized in the preparation of our proved reserve estimates are intended to ensure reliability of reserve estimations and include the following:

- review and verification of historical production data, which is based on actual production as reported by us;
- preparation of reserve estimates by the primary reserve engineers or under their direct supervision;
- review by the primary reserve engineers 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;

- review of historical realized commodity prices and differentials from index prices compared to the differentials used in the reserves database;
- direct reporting responsibilities by our Executive Vice President and Chief Engineer to our Executive Vice President and Chief Operating Officer;
- prior to finalizing the reserve report, a review of our preliminary proved reserve estimates by our Chief Executive Officer, Executive Vice President and Chief Financial Officer, Executive Vice President and Chief Operating Officer, Executive Vice President and Chief Engineer and our primary reserves engineers takes place on an annual basis;
- review of our proved reserve estimates by our Audit Committee with our executive team and Ryder Scott on an annual basis;
- verification of property ownership by our land department; and
- no employee's compensation is tied to the amount of reserves booked.

For estimates and further discussion of our proved developed and proved undeveloped reserves, see Note 18—Supplemental Information on Oil and Natural Gas Operations (Unaudited) in Item 8. Financial Statements and Supplementary Data of this report.

Potential Drilling Locations

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 $50.00 per Bbl WTI, we currently have approximately 8,854 gross (6,541 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 gross identified economic potential horizontal drilling locations by basin as of December 31, 2025:

	Number of Identified Economic Potential Horizontal Drilling Locations
Midland Basin:	
Lower Spraberry(1)	1,026
Middle Spraberry(1)	1,453
Wolfcamp A(2)	1,343
Wolfcamp B(2)	1,391
Wolfcamp D(3)	814
Other	1,883
Total Midland Basin	7,910
Delaware Basin:	
2nd Bone Springs(3)	325
3rd Bone Springs(3)	254
Wolfcamp A(3)	117
Wolfcamp B(3)	230
Other	18
Total Delaware Basin	944
Total	8,854

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

Oil and Natural Gas 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 the fields containing 15% or more, along with other production from fields containing less than 15%, of our total proved reserves:

	Midland Basin	Delaware Basin	Other	Total
Production Data:				
Year Ended December 31, 2025				
Oil (MBbls)	167,183	13,839	440	181,462
Natural gas (MMcf)	405,840	38,748	3,267	447,855
Natural gas liquids (MBbls)	74,512	5,395	166	80,073
Total (MBOE)	309,335	25,692	1,151	336,178
Year Ended December 31, 2024				
Oil (MBbls)	104,875	18,325	125	123,325
Natural gas (MMcf)	222,574	52,349	757	275,680
Natural gas liquids (MBbls)	41,559	8,084	57	49,700
Total (MBOE)	183,530	35,134	308	218,972
Year Ended December 31, 2023				
Oil (MBbls)	75,859	20,246	71	96,176
Natural gas (MMcf)	140,721	57,129	267	198,117
Natural gas liquids (MBbls)	25,899	8,296	22	34,217
Total (MBOE)	125,212	38,064	138	163,413

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

	Year Ended December 31,		
	2025	2024	2023
Average Prices:			
Oil ($ per Bbl)	$ 64.04	$ 73.52	$ 75.68
Natural gas ($ per Mcf)	$ 0.89	$ 0.32	$ 1.32
Natural gas liquids ($ per Bbl)	$ 17.88	$ 18.99	$ 20.08
Combined ($ per BOE)	$ 40.02	$ 46.12	$ 50.35
Oil, hedged ($ per Bbl)(1)	$ 63.14	$ 72.68	$ 74.72
Natural gas, hedged ($ per Mcf)(1)	$ 1.84	$ 0.91	$ 1.48
Natural gas liquids, hedged ($ per Bbl)(1)	$ 17.88	$ 18.99	$ 20.08
Average price, hedged ($ per BOE)(1)	$ 40.79	$ 46.38	$ 49.98
Average Costs ($/BOE):			
Lease operating expenses	$ 5.55	$ 5.87	$ 5.34
Production and ad valorem taxes	2.53	2.91	3.21
Gathering, processing and transportation expense	1.53	1.63	1.76
General and administrative - cash component	0.62	0.68	0.59
Total operating expense - cash	$ 10.23	$ 11.09	$ 10.90
General and administrative - non-cash component	$ 0.24	$ 0.30	$ 0.33
Depreciation, depletion, amortization and accretion	$ 14.99	$ 13.02	$ 10.68
Interest expense, net	$ 0.73	$ 0.62	$ 0.97
Production Costs(2)	$ 7.08	$ 7.50	$ 7.10

(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.

(2) Average production costs is comprised of lease operating expenses and gathering, processing and transportation expense.

Wells Drilled and Completed in 2025

The following table sets forth the total number of operated horizontal wells drilled and completed during the year ended December 31, 2025:

	Drilled		Completed	
Area:	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	459	426	488	463
Delaware Basin	4	4	15	13
Total	463	430	503	476

As of December 31, 2025, we operated the following wells in the Permian Basin:

	Vertical Wells		Horizontal Wells		Total	
Area:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	4,447	4,229	4,868	4,560	9,315	8,789
Delaware Basin	40	35	474	441	514	476
Total	4,487	4,264	5,342	5,001	9,829	9,265

Productive Wells

As of December 31, 2025, we owned an interest in a total of 55,662 gross productive wells with an average unweighted 82% working interest in 11,750 gross (9,642 net) wells and an average 2.0% royalty interest in 43,912 additional wells. Through our subsidiary, Viper, we own an average 2.2% net revenue interest in 43,355 of the total 55,662 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, 2025:

	Gross Wells			Net Wells		
	Oil	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
Midland Basin	30,114	239	30,353	9,007	68	9,075
Delaware Basin	9,390	3,220	12,610	462	19	481
Denver-Julesburg Basin	6,140	232	6,372	—	—	—
Other	5,400	927	6,327	27	59	86
Total productive wells	51,044	4,618	55,662	9,496	146	9,642

Drilling Results

The following tables set forth information with respect to the number of wells drilled 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, 2025					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	444	412	4	4	448	416
Dry	—	—	—	—	—	—
Exploratory:						
Productive	15	14	—	—	15	14
Dry	—	—	—	—	—	—
Total:						
Productive	459	426	4	4	463	430
Dry	—	—	—	—	—	—

	Year Ended December 31, 2024					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	322	308	30	26	352	334
Dry	—	—	—	—	—	—
Exploratory:						
Productive	20	17	—	—	20	17
Dry	—	—	—	—	—	—
Total:						
Productive	342	325	30	26	372	351
Dry	—	—	—	—	—	—

	Year Ended December 31, 2023					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	192	179	29	25	221	204
Dry	—	—	—	—	—	—
Exploratory:						
Productive	123	106	6	5	129	111
Dry	—	—	—	—	—	—
Total:						
Productive	315	285	35	30	350	315
Dry	—	—	—	—	—	—

As of December 31, 2025, we had 22 gross (21 net) operated wells in the process of drilling and 312 gross (290 net) wells in the process of completion or waiting on completion.

Acreage

The following table sets forth information as of December 31, 2025 relating to our leasehold acreage in the Permian Basin:

	Developed Acreage(1)		Undeveloped Acreage		Total Acreage(2)	
Basin:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland	506,360	402,952	476,332	371,693	982,692	774,645
Delaware	69,220	57,800	45,934	36,591	115,154	94,391
Total	575,580	460,752	522,266	408,284	1,097,846	869,036

(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, 2025, the following gross and net undeveloped acres are set to expire over the next five 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					
	Midland		**Delaware**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
2026	13,364	10,579	408	323	13,772	10,902
2027	28,991	22,949	—	—	28,991	22,949
2028	33,121	26,218	—	—	33,121	26,218
2029	780	617	—	—	780	617
2030	2,935	2,323	—	—	2,935	2,323
Total	79,191	62,686	408	323	79,599	63,009

Title to Properties

Prior to the drilling of an oil or natural gas well, 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. To the extent title opinions or other investigations reflect title defects impacting the development or operation of a producing property, 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. 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, an updated title review, 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 years ended December 31, 2025, 2024 and 2023 four 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 in Item 8. Financial Statements and Supplementary Data of this report.

Delivery Commitments

Certain of our firm sales agreements include delivery commitments that specify the delivery of a fixed and determinable quantity of oil. We expect our production and 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. In 2023, we began purchasing third-party volumes to fulfill certain delivery commitments. For additional information regarding commitments, see Note 15—Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data of this report.

Competition

The oil and natural gas industry is intensely competitive and we compete with other companies that may 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. 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, fuel oils and nuclear energy.

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 15% to 35%, resulting in a net revenue interest to us generally ranging from 65% to 85%.

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 buyers 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, 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.

Regulation

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements. Federal and state legislation and regulation affecting the oil and natural gas industry is evolving. 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. 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 may result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements that 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. Further, on January 20, 2025, President Trump issued a series of executive orders and memoranda signaling a shift in environmental and energy policy in the United States, including the revocation of several Biden administration-era executive orders related to public health, the environment, climate change and climate-related financial risks. President Trump also declared a "national energy emergency," directing agencies to expedite conventional energy projects. While the Trump Administration's changes to the environmental regulatory landscape in the United States continue to develop, it is possible that additional changes in the future could impact our results of operations and those of our customers.

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 the U.S. Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." 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. Additionally, emerging contaminants, like per- and polyfluoroalkyl substances ("PFAS") such as perfluorooctanesulfonic acid and perfluorooctanoic acid compounds, have become subject to CERCLA regulation in addition to existing federal and state chemicals regulation, and PFAS have recently been regulated under the Toxic Substances Control Act ("TSCA"). Other emerging contaminants could also become subject to regulation under CERCLA, TSCA or comparable state laws. 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. We cannot provide any assurance that the costs and liabilities associated with the future imposition of such remedial or regulatory compliance obligations upon us would not have a material adverse effect on our operations or financial position.

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 of 1990, 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.

The scope of waters regulated under the CWA has fluctuated in recent years due to notable rulemaking efforts and judicial challenges. On January 18, 2023, the EPA and the U.S. Army Corps of Engineers, or the Corps, jointly promulgated final rules expanding the scope of waters protected under the CWA. However, on May 25, 2023, the United States Supreme Court issued an opinion substantially narrowing the scope of "waters of the United States" protected by the CWA. On September 8, 2023, the EPA and the Corps published a final rule conforming their regulations to the decision. Later, on March 12, 2025, the EPA issued guidance narrowing the definition of "wetland" from the Biden-era definition in order to align that definition with the Supreme Court's May 25, 2023 decision. These recent actions have provided some clarity. However, to the extent the EPA and the Corps broadly interpret their jurisdiction and expand the range of properties subject to the CWA's jurisdiction, we or third-party operators 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. On March 12, 2025, the EPA announced that it is re-evaluating the existing regulations on oil and gas wastewater, including exploring opportunities for discharge from centralized wastewater treatment facilities. 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 if they are under common control 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 (including carbon dioxide, methane and other gases). Such rules and regulations have been proposed, amended and challenged, and finalized, and compliance deadlines have been extended or regulations rescinded. For example, the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022, or the IRA, include billions of dollars in incentives for the development of renewable energy and supporting infrastructure. In March 2024, the EPA published a final rule in the Federal Register to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from new and existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments. On November 26, 2025, the EPA issued an interim final rule to extend certain compliance deadlines from the March 2024 final rule. These incentives and regulations, if implemented, may encourage the transition of the economy away from the use of fossil fuels toward lower- or zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we produce and sell and adversely impact our business. In addition, the IRA imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge. The IRA amends the CAA to impose a "waste emissions charge" on the emission of methane that exceeds an applicable waste emissions threshold from sources required to report their greenhouse gas emissions to the EPA, including those sources in offshore and onshore petroleum and natural gas production and gathering and boosting source categories. On November 18, 2024, the EPA published a final rule on the methane emissions charge, which became effective on January 17, 2025. Twenty-three states filed a lawsuit challenging the CAA amendment, and the One Big Beautiful Bill Act, passed July 4, 2025, suspends the "waste emissions charge" from future implementation. The current U.S. presidential administration has also expressed an intention to scale back various other climate regulations launched under previous administrations. On February 12, 2026, the EPA issued a final rule eliminating the 2009 greenhouse gas endangerment finding, which underpins U.S. federal regulation of greenhouses gas emissions under the Clean Air Act. The final rule is expected to be subject to extensive litigation and the impact of such scaling back is difficult to predict at this time. Despite this shift, numerous proposals have been and continue to be made at the international, regional and state levels of government that are intended to limit emissions of greenhouse gases by enforceable requirements and voluntary measures.

The EPA has also finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry. On November 26, 2025, the EPA issued an interim final rule to extend certain compliance deadlines from the March 2024 final rule. Additionally, several states have 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.

In addition to domestic regulation of greenhouse gases, there continues to be international interest in a global framework for greenhouse gas reductions. However, on January 20, 2025, President Trump issued an executive order directing the United States Ambassador to the United Nations to immediately withdraw from the Paris Agreement and revoke the U.S. International Climate Finance Plan, and on January 27, 2025, the United States' Acting Ambassador to the United Nations submitted a notification of withdrawal from the Paris Agreement. The withdrawal became effective on January 27, 2026.

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.

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 the U.S. 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 March 8, 2024, the EPA published a final rule to expand and strengthen emission reduction requirements for both new and existing sources in the oil and natural gas industry by requiring increased monitoring of fugitive emissions, imposing new requirements for pneumatic controllers and tank batteries, and prohibiting venting of natural gas in certain situations. On December 1, 2025, the EPA published a final rule extending several compliance deadlines in the March 2024 final rule. This final rule was promptly challenged in federal court by environmental groups. While there is uncertainty regarding the scope and extent of EPA's regulation of air emissions from hydraulic fracturing operations, 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. Additionally, in the future, the EPA may impose more stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions, which may increase our compliance or operating costs.

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 and temporarily suspend operations for waste disposal wells. For example, in September 2021, the Texas Railroad Commission curtailed the amount of water companies were permitted to inject into some wells near Midland and Odessa in the Permian Basin, and has subsequently suspended some permits there and expanded the restrictions to other areas. In addition, the Texas Railroad Commission has imposed monitoring and reporting requirements for any new disposal well permitted in the Permian Basin. These restrictions on use of produced water, a moratorium on new produced water disposal wells, and additional monitoring and reporting requirements could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or pump it through the pipeline network or other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, or require us or our service providers to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling and completion activity in the affected parts of the Permian Basin less economical and adversely impact our business, results of operations and financial condition.

On December 17, 2024, the Texas Railroad Commission adopted a significant overhaul of its rules regulating oil and gas waste management facilities in Texas. The new rules went into effect on July 1, 2025. The new rules, found in 16 TAC Chapter 4, cover waste from oil and gas operations, such as rock and other material pulled up from the ground during drilling, as well as waste from other operations. The rules impose requirements related to waste management practices and production methods, such as recycling produced water. The rules also update requirements on the design, construction, operation, monitoring, and closure of waste management units.

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, such as the lesser prairie chicken or dunes sagebrush lizard, are located in areas where we operate, our operations or any work performed related to them could be prohibited or delayed, or expensive mitigation could 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.

However, the designation of previously unprotected species as threatened or endangered in areas where we operate 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 of oil and natural gas significantly affect its marketability and sale. The interstate transportation and sale for resale of natural gas, and the interstate transportation of oil, is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by FERC. Oil and natural gas pipelines are also subject to extensive safety regulation by the Pipeline and Hazardous Materials Safety Administration, a part of the U.S. Department of Transportation, and state regulatory agencies. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC regulation of interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas, which is predominantly state-regulated.

Although oil and natural gas prices are currently unregulated, the U.S. 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 the U.S. 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. 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 under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Beginning with that legislation in 1978 and continuing with the Wellhead Decontrol Act of 1989, 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 for violations. We are subject to that FERC authority and related policies.

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, the U.S. 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 (including other liquid hydrocarbons) in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. We are subject to such regulation when we provide such interstate transportation of oil in our midstream operations, and we have a tariff on file with FERC for that purpose. 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 ours and those on which we transport oil, 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, we are 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.

We are also subject to the Pipeline Safety Improvement Act of 2002. 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 PHMSA regulations also provide for the inspection and testing of pipelines and the correction of anomalies, and require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans and spill response training for pipeline personnel.

The Pipeline Safety and Job Creation Act, enacted in 2011, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, also known as the PIPES Act, amended the HLPSA 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 $272,926 and $2,729,245, 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. Also, on November 15, 2021, PHMSA published a final rule extending reporting requirements to all onshore gas gathering operators and establishing a set of minimum safety requirements for certain gas gathering pipelines with large diameters and high operating pressures, and, on August 24, 2022, PHMSA published a final rule strengthening integrity management requirements for onshore gas transmission lines, bolstering corrosion control standards and repair criteria, and imposing new requirements for inspections after extreme weather events. In October 2024, PHMSA issued a notice of proposed rulemaking recommending modernizing and simplifying the hazardous material regulations, enhancing safety standards across rail, highway, and vessel transportation while also providing annual cost savings for businesses and consumers. Following the change in Presidential Administration, PHMSA in January 2025 extended the public comment period for the rulemaking until April 28, 2025, but has not otherwise acted on that proposed rulemaking. In May 2025, PHMSA issued two Advance Notices of Proposed Rulemaking ("ANPRM") seeking public comment on updates to its safety regulations for pipelines and LNG facilities aimed at implementing the President's "Unleashing American Energy" Executive Order. In June 2025, PHMSA issued another ANPRM to solicit stakeholder feedback on whether to repeal or amend any requirements in its pipeline safety regulations to eliminate undue burdens on the identification, development, and use of domestic energy resources and to improve government efficiency.

The ultimate impact of those efforts of the Trump Administration remains to be seen. If safety standards were to become more stringent in the future, it could cause us, like other similarly situated pipeline operators, to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated or expanded 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 for any violations 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 been certified by PHMSA to assume responsibility to enforce the federal standards. For example, on December 17, 2019, the Texas Railroad 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 applicable pipeline safety and pollution control requirements.

In addition to PHMSA regulation, we are subject to the requirements of 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. 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, control of well protection for all wells, comprehensive general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date and occurrence-based coverage for sudden, accidental releases), excess umbrella liability and other coverage.

Our insurance is subject to certain exclusions 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 of this report for additional information regarding operating hazard and uninsured risks.

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 property damage and injuries and deaths of the service provider’s employees as well as contractors and subcontractors hired by the service provider.

Human Capital

We have built a culture grounded upon the solid foundation of our core values—leadership, integrity, excellence, people and teamwork—which guide how we operate across the organization. We set high expectations for all of our employees in terms of how they operate and interact, in the office, in the field and in the community. We challenge them to identify new ways to foster a better future for themselves and for our organization. Our board of directors, through its Safety, Sustainability and Corporate Responsibility Committee (the “SS&CR Committee”), provides an important oversight of our human capital management strategy, including on issues of diversity, equity and inclusion. The SS&CR Committee receives regular updates from our executive leadership, senior management and third-party consultants on human capital trends and other key human capital matters impacting our business.

We ended the year 2025 with 1,762 full-time employees. None of our full-time employees are represented by labor unions or covered by any collective bargaining agreements. In addition, we engage independent contractors and consultants in land, technical, regulatory and other disciplines to support our full-time employees.

Equal Opportunity, Recruiting and Retention

Equal employment opportunity is a core principle of our organization. We are committed to attracting and retaining top talent and fostering a respectful work environment. Our employment decisions are guided by merit, qualifications, competencies and demonstrated contributions in compliance with all applicable laws. We value the diverse perspectives, experiences and ideas contributed by employees from a wide range of ethnic, cultural and ideological backgrounds. As of December 31, 2025, approximately 25% of our employees are women and 40% self-identify as ethnic minorities. To further support transparency around our workforce demographics, we disclosed our 2024 Equal Employment Opportunity data in our 2025 Corporate Sustainability Report.

In 2025, we expanded our recruitment efforts, with a particular focus on college recruitment and internship programs. We collaborated with several student organizations to reinforce this inclusive initiative, which will continue in the future. Our focus on military recruiting and partnerships with two-year technical schools for technical talent remain a priority for field operations. In addition, we have focused on recruiting experienced hires to target and retain top industry talent. In 2025, our total attrition rate was approximately 19%, which includes our remaining Endeavor Energy Resources integration efforts and asset divestitures. Excluding these factors, our adjusted attrition rate was approximately 8%. We believe our ability to retain talent is supported by our corporate culture, which emphasizes diversity and inclusion, teamwork and a strong commitment to employee development and career advancement.

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. We also strive to comply with all applicable health, safety and environmental standards, laws and regulations.

We have committed to reduce injuries and fatalities in our business and are focused on safety culture improvements, safety leadership actions and human performance principles. We require our operational employees and independent contractors and their employees to go through orientation and training aligned with the International Association of Oil and Gas Producers Life Saving Rules, a program that also meets the operational safety requirements adopted by the American Petroleum Institute. We also involve employees from all operational levels in our safety program to provide input and suggested improvements to the overall safety program, recommend preventative measures based on reviewing vehicle and personnel incidents, perform safety and environmental audits at operational locations and participate in the audit and oversight of the Diamondback Hazard Communication Program.

Since inception, we have had no employee work-related fatalities. Our employee OSHA recordable cases, comprising work-related injuries and illnesses that require medical treatment beyond first aid, totaled 11 in 2025, consistent with 11 in 2024. Our employee total recordable incident rate (TRIR) was 0.62 in 2025, down from 0.82 in 2024, and lost-time incident rate was 0.45 in 2025 consistent with 0.45 in 2024. At December 31, 2025, we had a short-term goal of maintaining an employee TRIR of 0.25 or less.

Training and Development

We support employees in pursuing training opportunities to expand their professional skills. Our internal course offerings in 2025 included a wide array of topics in addition to extensive safety and other compliance training sessions. Additionally, our people undergo training and education each year on regulatory compliance, industry standards and innovative opportunities to effectively manage the challenges of developing our resources. We have also implemented development programs that are designed to build leadership capabilities at all levels.

Our Facilities

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

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. Reports filed or furnished with the SEC are also made available on its website at www.sec.gov.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following is a summary of the material risks relating to our business activities. 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.

The following is a summary of the principal risks that could adversely affect our business, operations and financial results:

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

- Geopolitics and market conditions, and particularly volatility in prices for oil and natural gas, may adversely affect our revenue, cash flows, profitability, growth, production and the present value of our estimated reserves.
- Our commodity price derivatives could result in financial losses, may fail to protect us from declines in commodity prices, prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty credit risk.
- Changes in U.S. trade policy and the impact of tariffs may have a material adverse impact on our business and results of operations.
- Risks relating to the transition to a low carbon economy could impose new costs on our operations that may have a material and adverse effect on us.
- Changing political and social perspectives on climate change and other environmental, social and governance factors may create risks and uncertainties impacting our business.
- Our targets related to sustainability and emissions reduction initiatives, including our public statements and disclosures regarding them, may expose us to numerous risks.
- Our success depends on developing our existing leasehold acreage and finding, developing or acquiring additional reserves.
- We may be unable to obtain needed capital or financing on satisfactory terms or at all to fund our acquisitions, exploration or development activities.
- Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings.
- Our identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- We may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contracts.
- The loss of one or more of our customers or their inability to meet their obligations 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 reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved 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, supplies, oilfield services or personnel become unavailable or too costly, our operations could be interrupted and our revenues reduced.
- Restrictions on our ability to obtain water and dispose of produced water, and additional monitoring and reporting requirements related to existing and new produced water disposal wells in the Permian Basin could adversely impact our business, results of operations and financial condition.
- Our planned exploratory drilling in existing or emerging shale plays is subject to risks associated with drilling and completion techniques.
- Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive.
- U.S. tax legislation may negatively affect our business, results of operations, financial condition and cash flow.
- 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.
- Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.
- We may not be able to keep pace with technological developments in our industry.
- 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.
- Legal proceedings brought against us could result in substantial liabilities and materially and adversely impact our financial condition.
- Failure to comply with cybersecurity and data privacy laws and regulations could have a material effect on our reputation, results of operations or financial loss.
- Following the closing of the Endeavor Acquisition, the Endeavor equityholders have the ability to significantly influence our business, and their interest in our business may be different from that of other stockholders.

Risks Related to Our Indebtedness

- Our substantial level of indebtedness could adversely affect our results of operations, business flexibility and our ability to service our debt.
- A downgrade in our debt ratings could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Risks Related to Our Common Stock

- 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 and certain other tax attributes.
- 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.
- The provision of our certificate of incorporation and bylaws requiring exclusive venue in the Court of Chancery in the State of Delaware for certain types of lawsuits may have the effect of discouraging lawsuits against us and our directors, officers and employees.

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

Geopolitics and 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; regional conflicts and political instability; the continued threat of terrorism, including attacks targeting oil and gas facilities and the impact of military and other action; the ability of members of OPEC+ 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; global or national health concerns, including the outbreak of pandemic or contagious disease; the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and overall domestic and global economic conditions. Our results of operations may also be 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.

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. From the beginning of 2023 through the end of 2025, WTI prices ranged from $55.27 to $93.68 per Bbl and the Henry Hub price of natural gas ranged from $1.58 to $5.29 per MMBtu. If the prices of oil and natural gas decline, our production, proved reserves and cash flows are likely to be adversely impacted.

Our commodity price derivatives could result in financial losses, may fail to protect us from declines in commodity prices, prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty credit risk.

We use commodity price derivatives, which have historically included swaps, basis swaps, swaptions, roll hedges, costless collars, puts and basis puts, to reduce price volatility associated with certain of our oil, natural gas and natural gas liquids sales. Currently, we have hedged a portion of our estimated 2026 and 2027 production. To the extent that the prices of oil, natural gas and natural gas liquids remain at current levels or decline further, we may not be able to economically hedge additional future production at the same level as our current commodity price derivatives, and our results of operations and financial condition may be negatively impacted. While these commodity price derivatives are intended to mitigate risk from commodity price volatility, we may be prevented from fully realizing the benefits of increases in the prices of oil, natural gas and natural gas liquids above the price levels of the commodity price derivatives used to manage price risk.

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.

Additionally, U.S. and non-U.S. derivatives reforms (including the Dodd-Frank Act) impose clearing, margin and other requirements. While we do not expect material direct effects, our counterparties' compliance could increase our hedging costs, limit instrument availability, and heighten counterparty credit exposure, leading to greater earnings and cash flow volatility. These regulations could also depress commodity prices, further reducing our revenues.

For additional information regarding our outstanding derivative contracts as of December 31, 2025, see Note 12—Derivatives in Item 8. Financial Statements and Supplementary Data, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk of this report.

Changes in U.S. trade policy and the impact of tariffs may have a material adverse effect on our business and results of operations.

Our business and results of operations may be adversely affected by uncertainty and changes in U.S. trade policies, including tariffs, trade agreements or other trade restrictions imposed by the U.S. or other governments. The recent uncertainty over such policies has caused substantial volatility in commodity, capital and financial markets, increased concerns over domestic and global inflation and adversely impacted consumer confidence in the U.S. and worldwide.

Tariffs or other trade restrictions may lead to continuing uncertainty and volatility in U.S. and global financial and economic conditions and commodity markets, declining consumer confidence, significant inflation and diminished expectations for the economy, and ultimately reduced demand for oil and natural gas. Such conditions could have a material adverse impact on our business, results of operations and cash flows. Also, disruptions and volatility in the financial markets may lead to adverse changes in the availability, terms and cost of capital. Such adverse changes could increase our costs of capital and limit our access to external financing sources to fund acquisitions, repurchases of securities or other capital requirements.

Changes in tariffs and trade restrictions can be announced with little or no advance notice. The adoption and expansion of tariffs or other trade restrictions, increasing trade tensions, or other changes in governmental policies related to taxes and tariffs, are difficult to predict, which makes attendant risks difficult to anticipate and mitigate. If we are unable to navigate further changes in U.S. or international trade policy, it could have a material adverse impact on our business and results of operations.

Risks relating to the transition to a low carbon economy could impose new costs on our operations that may have a material and adverse effect on us.

Governmental and regulatory bodies, investors, consumers, industry and other stakeholders have evolving and varied views on climate change matters in recent years. Such views, together with changes in consumer and industrial/commercial behavior, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in: (i) the enactment of new or evolving climate change-related regulations, policies and initiatives by governments, investors, and other companies, including alternative energy or "zero carbon" requirements and fuel or energy conservation measures; (ii) technological advances with respect to the generation, transmission, storage and consumption of energy (including advances in battery technology); (iii) variability in demand from consumers and industry for energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles); and (iv) development of, and variable demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services.

Any of these developments may reduce the demand for products manufactured with (or powered by) hydrocarbons and the demand for, and in turn the prices of, the oil and natural gas that we produce and sell, which would likely have a material adverse impact on us. If any of these developments reduce the desirability of participating in the oilfield services, midstream or downstream portions of the oil and gas industry, then these developments may also reduce the availability to us of necessary third-party services and facilities that we rely on, which could increase our operational costs and adversely affect our ability to explore for, produce, transport and process oil and natural gas and successfully carry out our business and financial strategy.

The enactment of climate change-related regulations, policies and initiatives may also result in increases in our compliance costs and other operating costs and have other adverse effects, such as a greater potential for governmental investigations or litigation. For further discussion regarding the risks to us of climate change-related regulations, policies and initiatives, please see the section entitled Items 1 and 2. Business and Properties—Regulation—Climate Change of this report.

In addition to potentially reducing demand for our oil and natural gas and potentially reducing the availability of oilfield services and midstream and downstream customers, further regulatory or other climate change incentives, to the extent they continue, may create investment and reputational risks associated with the exploration for, and production of, hydrocarbons, which may adversely affect the availability and cost to us of capital. Certain stakeholders and capital providers may seek to restrict or seek to impose stringent conditions with respect to their investment in or financing of certain carbon intensive sectors, which could result in capital being unavailable to us, or only at significantly increased costs.

Changing political and social perspectives on climate change and other environmental, social and governance factors may create risks and uncertainties impacting our business.

We may not be able to meet evolving expectations of stakeholders, including governmental officials, standard setters, investors, employees, and customers, relating to climate change, human capital, and other ESG issues. For example, while some policymakers, including the European Union and the State of California, have adopted disclosure and other requirements relating to ESG matters, other policymakers have sought to constrain companies' consideration of such matters. Further, shareholders have sought to effect changes to public companies' businesses or governance to deal with climate change-related issues through shareholder proposals, public campaigns, proxy solicitations or other actions. Any such future actions may result in significant management distraction and potentially significant expense.

Additionally, cities, counties, and other governmental entities in several states in the U.S. have filed lawsuits against energy companies seeking damages allegedly associated with climate change. Similar lawsuits may be filed in other jurisdictions. If any such lawsuits were to be filed against us, whether due to our activities or the activities of the acquired entities or operations prior to their acquisition by us, we could incur substantial legal defense costs and, if any such litigation were adversely determined, we could incur substantial damages.

Any of these climate change-related litigation risks could result in unexpected costs, negative sentiments about our company, disruptions in our operations, and increases to our operating expenses, which in turn could have an adverse effect on our business, financial condition and results of operations.

Our targets related to sustainability and emissions reduction initiatives, including our public statements and disclosures regarding them, may expose us to numerous risks.

We have developed, and will continue to develop, targets related to our ESG initiatives, including our emissions reduction targets and strategy. Statements in this and other reports we file with the SEC and other public statements related to these initiatives reflect our current plans and expectations and are not a guarantee the targets will be achieved or achieved on the currently anticipated timeline. Our ability to achieve our ESG targets, including emissions reductions, is subject to numerous factors and conditions, some of which are outside of our control, and failure to achieve our announced targets or comply with ethical, environmental or other standards, including reporting standards, may expose us to government enforcement actions or private litigation and adversely impact our business. Further, our continuing efforts to research, establish, accomplish and accurately report on these targets may create additional operational risks and expenses and expose us to reputational, legal and other risks.

Further, in response to the evolving regulatory environment and investor expectations, or due to our acquisitions of other companies or assets, we may, periodically, make adjustments to our environmental targets or goals. If we do not, or are perceived to not, adapt or comply with certain investor or stakeholder expectations and standards on ESG matters, we may suffer from reputational damage and our business, financial condition and results of operations could be materially and adversely affected. Any reputational damage associated with ESG factors may also adversely impact our ability to recruit and retain employees and customers.

Our success depends on developing our existing leasehold acreage and finding, developing or acquiring additional reserves.

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 to maintain the production in paying quantities, and if we are unsuccessful in drilling such wells and maintaining such production, 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.

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 in paying quantities 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. Any non-renewal or other loss of leases could materially and adversely affect the growth of our asset basis, cash flows and results of operations.

We use 2-D and 3-D seismic data to identify the presence of oil and natural gas. 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.

Additionally, 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. 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.

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 2025, our total cash capital expenditures were approximately $3.5 billion. Our 2026 cash capital budget is currently estimated to be approximately $3.60 billion to $3.90 billion, representing an increase at the midpoint of 6% from our 2025 capital expenditures.

We intend to finance our future capital expenditures 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 2026 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, 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 or our costs of capital increase, 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.

In addition, approximately 30% of our total estimated proved reserves as of December 31, 2025, were proved undeveloped reserves and may not be ultimately developed or produced. 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 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, including title defects or environmental issues, 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. Environmental or other regulatory issues may arise with respect to acquired entities or operations years after the acquisitions. 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, 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.

Any of these factors could have a material adverse effect on our financial condition and results of operations. Our financial position and results of operations may also fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

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.

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.

As of December 31, 2025, we have approximately 8,854 gross (6,541 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage at an assumed price of approximately $50.00 per Bbl WTI. As of December 31, 2025, only 1,351 of our gross identified economic potential horizontal drilling locations in which we have a working interest 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, unusual or unexpected geological formations, title problems, facility or equipment malfunctions, unexpected operational events, inclement weather, environmental and other regulatory requirements 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, as of December 31, 2025, we have identified approximately 1,901 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. Through December 31, 2025, we are the operator of, have participated in, or have acquired working interest in a total of 6,677 horizontal producing 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.

We may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contracts, 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 our counterparties. 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 reduced 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 loss of one or more of our customers or their inability 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 and receivables from purchasers of our oil and natural gas production. 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. See Items 1 and 2. Business and Properties—Marketing and Customers of this report for additional information regarding these customers. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic and other conditions. We do not require our customers to post collateral. Under certain circumstances, the amounts due to them can be offset by any unpaid receivables. The loss of one or more of these customers, our inability to sell our production to other customers on terms we consider acceptable, 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.

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 approximately $3.7 billion was recorded for the year ended December 31, 2025. No impairments were recorded on our proved oil and natural gas properties for the years ended December 31, 2024 and 2023. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates—Oil and Natural Gas Accounting and Reserves of this report. If the prices of oil and natural gas decline, we may be required to further write-down the value of our oil and natural gas properties in the future, which could negatively affect our results of operations.

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, and 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 is not necessarily the same as the current market value of our estimated proved reserves.

The present value of future net cash flows from our proved reserves or standardized measure may not represent the current market value of our estimated proved reserves. 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.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks (including weather-related 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, 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 and their adverse impact on production volumes, availability of electrical power, road accessibility and transportation facilities.

Extreme regional weather events may occur that can affect our suppliers or customers, which could adversely affect us. For example, a significant hurricane or similar weather event could damage refining and other oil and natural gas-related facilities on the Gulf Coast of Texas and Louisiana, which (if significant enough) could limit the availability of gathering and transportation facilities across Texas and could then cause production in the Permian Basin (including potentially our production) to be curtailed or shut in or (in the case of natural gas) flared. Climate change may also increase the frequency and severity of significant weather events over time. Further, any increase in flaring of our natural gas production due to weather-related events or otherwise could make it difficult for us to achieve our publicly-announced sustainability and emissions reduction targets, which could expose us to reputational risks and adversely impact our contractual and other business relationships. Any of the above-referenced events could have a material adverse effect on us and our production volumes (and therefore on our financial condition and results of operations).

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, 2025, 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.

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 operators of those rigs may choose to cease providing services to us. Shortages of any of the items referenced above 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. Also, in 2021, the Texas Legislature directed the Texas Railroad Commission to adopt rules encouraging fluid oil and gas waste recycling. On January 3, 2025, the Commission published final amendments to its water protection rules to, among other things, encourage waste recycling. The revised rules went into effect on July 1, 2025. 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.

Recent regulatory restrictions on the disposal of produced water and additional monitoring and reporting requirements related to existing and new produced water disposal wells in the Permian Basin to stem rising seismic activity and earthquakes could increase our operating costs and adversely impact our business, results of operations and financial condition.

In September 2021, the Texas Railroad Commission curtailed the amount of produced water companies were permitted to inject into some wells near Midland and Odessa in the Permian Basin and has since indefinitely suspended some permits there and expanded the restrictions to other areas. These actions were taken in an effort to control induced seismic activity and recent increases in earthquakes in the Permian Basin, which have been linked by the U.S. and local seismologists to wastewater disposal in oil fields. The Texas Railroad Commission has since adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. These restrictions and additional monitoring and reporting requirements related to existing and new produced water and produced water disposal wells could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or dispose of it by other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, or require us or our service providers to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling activity in the affected parts of the Permian Basin less economical and adversely impact our business, results of operations and financial condition.

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 developing and utilizing the latest drilling and completion techniques. Risks that we face while drilling include, but are not limited to, spacing of wells to maximize economic return; 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; run tools the entire length of the well bore during completion operations; successfully clean out the well bore after completion of the final fracture stimulation stage; and prevent unintentional communication with other wells.

Furthermore, certain of the 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 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.

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. 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.

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.

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 Items 1 and 2. Business and Properties—Regulation of this report for a detailed description of certain laws and regulations that affect us.

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 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.

In 2022, the IRA enacted a 15% corporate alternative minimum tax (“CAMT”) on the “adjusted financial statement income” of certain large corporations (generally, corporations reporting more than $1 billion average adjusted pre-tax net income on their consolidated financial statements) for tax years beginning after December 31, 2022. While we are subject to CAMT, we did not incur a CAMT liability for 2025.

On July 4, 2025, the One Big Beautiful Bill Act (the “OBBB”) was signed into law. Among other provisions, the OBBB provides for immediate expensing of research or experimental expenses, bonus depreciation for qualified tangible property, deductible intangible drilling costs for purposes of the CAMT, and enhancements to limits on business interest expense deductions. The OBBB also imposes limits on deductibility of charitable contributions by corporations. For 2025, the net effect of the OBBB was to accelerate our tax deductions and thus favorably affect our cash flow, but to the extent that our tax deductions may be limited or deferred by the applicable provisions of the OBBB in future periods, the amount and timing of our cash tax obligations may be adversely affected.

The U.S. Treasury Department, the Internal Revenue Service (“IRS”) and other standard-setting bodies are expected to issue additional guidance on how the CAMT and other provisions of the IRA and OBBB will be applied or otherwise administered, and such guidance may differ from our interpretations. We continue to evaluate the IRA and OBBB and their effect on our financial results and operating cash flow.

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.

In addition, 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 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.

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.

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.

Additionally, the development, deployment and use of artificial intelligence ("AI") and machine learning in our operations and those of our service providers and partners could introduce new risks, including increased exposure to cybersecurity threats and social engineering, inadvertent disclosure or misuse of confidential, proprietary or personal information, errors, bias or other unexpected outcomes in AI outputs used for operational decision-making, and evolving and potentially divergent regulatory requirements that may restrict certain uses of AI or increase compliance costs. AI adoption may require significant investment, specialized talent and access to high-quality data, and our competitors may adopt AI more effectively than we do. Failures or limitations in AI tools, misuse by employees or third parties, or disruptions or breaches involving AI-enabled systems could adversely affect our business, reputation, financial condition and results of operations.

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.

Rapid growth in AI-related data centers and other high-intensity computing is materially increasing regional electricity demand and straining grids, which—together with extreme weather conditions, intermittent renewable generation, and other market constraints—can reduce power availability, increase prices (including scarcity pricing), and cause outages. Reduced power reliability could disrupt our drilling, completion, and production activities; impair midstream operations; hinder remote monitoring and data integrity; and force suspensions or shutdowns or unplanned spending on backup power and communications, any of which could have a material adverse effect on our business and results of operations.

Legal proceedings brought against us could result in substantial liabilities and materially and adversely impact our financial condition.

Like many oil and gas companies, we are involved in various legal proceedings, including threatened claims, such as contractual, title and royalty disputes. The cost to settle legal proceedings (asserted or unasserted) or satisfy any resulting unfavorable judgment against us in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact our cash flows, operating results and financial condition for the period in which any such effect becomes reasonably estimable. Judgments and estimates to determine accruals or range of losses related to legal proceedings are difficult to predict and could change from one period to the next, and such changes could be material. Current accruals may be insufficient to satisfy any such judgments. Legal proceedings could also result in negative publicity about the Company. Defending these actions, especially purported class actions, can be costly and can distract management and other personnel from their primary responsibilities. In addition, many of our proceedings are in their early stages. Where this is the case, the allegations and damage theories have not been fully developed, and are all subject to inherent uncertainties. As a result, management's view of the likelihood of a material and adverse financial impact from any such proceeding may change in the future. See Note 15—Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data of this report.

Failure to comply with cybersecurity and data privacy laws and regulations could have a material adverse effect on our reputation, results of operations or financial condition.

We rely extensively on information technology systems and infrastructure, including but not limited to, data hosting platforms, real-time data acquisition systems, internally developed and third-party software, cloud services and other internally or externally hosted hardware and software platforms (collectively, “IT Systems”) for operational and other purposes, such as to (i) estimate our oil and natural gas reserves, (ii) process and record financial and operating data, (iii) process and analyze all stages of our business operations, including exploration, drilling, completions, production, transportation, pipelines and other related activities, and (iv) communicate with our employees and vendors, suppliers and other third parties. We own and manage certain IT Systems but also rely on third parties for a range of IT Systems and other products or services. We and certain third-party providers also collect, maintain and/or process proprietary data about our business, such as trade secrets, as well as personally identifiable information about our employees, business partners and others (collectively, “Confidential Information”).

We regularly experience attempted cyberattacks and other incidents, including phishing attacks and attacks on certain of our third-party providers, and we expect future cyberattacks and incidents to occur in varying degrees. To date, no incidents have materially affected our company, including our business strategy, results of operations or financial condition, but we cannot guarantee that material incidents will not occur in the future.

Our IT Systems and Confidential Information, and that of our vendors, service providers and other third-party providers and business partners, are vulnerable to evolving cybersecurity threats, including, without limitation, denial-of-service attacks; malicious software (e.g., ransomware); the exploitation of known and unknown misconfigurations, “bugs,” and other hardware or software vulnerabilities; data privacy breaches by employees, insiders or others with authorized access; social engineering (e.g. phishing) attacks; attempts to gain unauthorized access to our data and systems; and other electronic or physical security breaches. More recently, advancements in AI pose serious risks for many of the traditional tools used to identify individuals, including voice recognition (whether by machine or the human ear), facial recognition or screening questions to confirm identities. In addition, generative AI systems are increasingly used by malicious actors to create more sophisticated cyber-attacks (i.e., more realistic phishing or other attacks) and to circumvent controls, evade detection and even remove forensic evidence, rendering incident detection and remediation more challenging. These and other threat-related advancements expose us to increasing costs, including costs to deploy additional personnel, protection technologies and policies and procedures, train employees, and engage third-party experts and consultants. There can be no assurance that our cybersecurity risk management program, including our controls or processes, will be fully implemented, complied with or effective in protecting our IT Systems and Confidential Information. Moreover, we do not manage the security controls or processes deployed by our third-party providers, such as cloud services that support our operations, and therefore, successful cyberattacks that disrupt or result in unauthorized access to third-party IT Systems could materially impact our operations and financial results. Similarly, we have acquired and continue to acquire companies that may have cybersecurity vulnerabilities or unsophisticated measures, which exposes us to significant risk.

A significant cybersecurity attack or incident that compromises our Confidential Information or disrupts our normal operations, including our exploration, completion, production and corporate functions, could materially and adversely affect us in a variety of ways, including, but not limited to the following: exploitation of our Confidential Information such as business data, reserves information, strategic information or other sensitive or proprietary information or personal information of our employees, vendors, service providers, royalty and working interest owners, or other third parties; damage to our ability to compete for oil and gas resources or our competitive advantage over other companies; failure to reach the intended target or a drilling incident; loss of production or accidental discharges; supply chain disruptions resulting from attacks on third party providers, vendors or business partners that delay or halt our operations, result in reduced demand for our production or delay or prevent us from transporting and marketing our production, in either case resulting in a loss of revenues; a cybersecurity attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues; a deliberate corruption of our financial or operating data could result in events of non-compliance, which could then lead to regulatory enforcement actions, fines or penalties; a cybersecurity attack on a communications network or power grid, which could cause operational disruptions resulting in a loss of revenues; and a cybersecurity attack on our automated and surveillance systems, which could cause a loss of production and potential environmental hazards. We could also be subject to significant regulatory investigations and enforcement actions, fines and penalties and/or legal claims that result in a material impact to our business, operating results or financial condition.

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.

A variety of U.S. federal, state and international laws and regulations govern the collection, use, retention, sharing and security of personal data. All 50 states have enacted legislation on data breach notification requirements and many states continue to enact laws on matters of privacy, data protection and cybersecurity. The existing privacy-related laws and regulations are evolving and subject to potentially differing interpretations. In addition, various U.S. federal, state and foreign legislative and regulatory bodies continue to enact new laws regarding privacy and data protection, as well as expand the scope of existing laws. We cannot predict the impact of any such evolving privacy-related laws on our business, operations or financial condition, but may find it necessary to enhance our existing systems and procedures, which may involve substantial expense or distraction from other aspects of our business. In addition, any violations of applicable privacy-related laws or regulations may require us to address legal claims, sustain monetary penalties or incur other liabilities, as well as cause reputational damage, any of which could adversely impact our business, results of operations or financial condition.

Following the closing of the Endeavor Acquisition, the Endeavor equityholders have the ability to significantly influence our business, and their interest in our business may be different from that of other stockholders.

As of December 31, 2025, Endeavor's equityholders held approximately 35.8% of our common stock. Pursuant to an agreement with the Endeavor equityholders, the Company appointed four additional directors to our board of directors of the Company. We will not be permitted to take certain actions without the consent of the holders of a majority of the shares of our common stock held by the Endeavor equityholders. The Endeavor equityholders' level of ownership and influence may make some transactions (such as those involving mergers, material share issuances or changes in control) more difficult or impossible, which in turn could adversely affect the market price of our shares of common stock or prevent our shareholders from realizing a premium over the market price for their shares of our common stock. The interests of the Endeavor equityholders may conflict with the interests of other stockholders, including that Endeavor equityholders may decide to reduce their investment in us. Such sales of our common stock or the perception that these sales may occur could have the effect of depressing the market price for our common stock.

Risks Related to Our Indebtedness

Our substantial indebtedness could adversely affect our results of operations, business flexibility and our ability to service our debt.

We have incurred a substantial amount of debt to finance our recent acquisitions and for other corporate purposes. 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. If we are unable to generate sufficient cash flow to service our debt, 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 alternative financing plans would be consummated on desirable terms or would be adequate to meet any debt service obligations then due.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future under our current debt agreement. Our increased level of debt could have negative consequences on us, including, among other things, (i) requiring us to dedicate a larger portion of cash flow from operations to servicing and repayment of the debt, (ii) reducing funds available for strategic initiatives and opportunities, working capital and other general corporate needs, (iii) limiting our ability to incur additional indebtedness, which could restrict our flexibility to react to changes in our business, our industry and economic conditions, and (iv) placing us at a competitive disadvantage compared to our competitors that have less debt.

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. 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. If a 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.

Lastly, our earnings are exposed to interest rate risk associated with borrowings under our and Viper's revolving credit facilities and under our Term Loan Agreement. The terms of the term loan and revolving credit facilities provide for interest on borrowings at a floating rate equal to an alternate base rate tied to SOFR. SOFR tends to fluctuate based on multiple factors, including general short-term interest rates, rates set by the U.S. Federal Reserve and other central banks and general economic conditions. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

A downgrade in our debt ratings 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.

Risks Related to Our Common Stock

The declaration of base and variable 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.

The decision to pay any future base and variable 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. Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, whether base or variable, or declare dividends at rates that are less than currently anticipated, either of which could reduce returns to our stockholders.

In July 2025, our board of directors approved an increase in our common stock repurchase program to acquire up to $8.0 billion. We may be limited in our ability to repurchase shares of our common stock by various governmental laws, rules and regulations which prevent us from purchasing our common stock during periods when we are in possession of material non-public information. Through December 31, 2025, approximately $5.3 billion has been repurchased through the repurchase program. Even though this program is in place, we may not repurchase any shares through the program and any such repurchases are completely within the discretion of our board of directors. In addition, the stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time. Any elimination of, or reduction in, the Company's base or variable dividend or common stock repurchase program could adversely affect the total return of an investment in and have a material adverse effect on the market price of our common stock.

Despite our return of capital commitment to return at least 50% of Adjusted Free Cash Flow to stockholders, the amount of cash available to return to our stockholders, if any, can vary significantly from quarter to quarter for a number of reasons, including commodity prices, liquidity, debt levels, capital resources and other factors. The price of our common stock may deteriorate if we are unable to meet investor expectations with respect to the timing and amount of our return of capital commitment to our shareholders, and such deterioration may be material.

A change of control could limit our use of net operating losses and certain other tax attributes.

Under Sections 382 and 383 of the Internal Revenue Code of 1986, as amended (the "Code"), a corporation that experiences an "ownership change" (as defined in the Code) may be subject to limitations on its ability to offset taxable income arising after the ownership change with net operating losses ("NOLs") and other tax attributes (such as tax credits and capital loss carryforwards) generated prior to the ownership change. In general, an ownership change occurs if there is a cumulative increase in the ownership of a corporation's 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. An ownership change would establish an annual limitation on the amount of a corporation's pre-change NOLs, tax credits and capital loss carryforwards that could be utilized to offset taxable income in any future taxable year. The amount of the limitation is generally equal to the value of the corporation's stock immediately prior to the ownership change multiplied by an interest rate, referred to as the long-term tax-exempt rate, periodically promulgated by the IRS. This limitation, however, may be significantly increased if there is “net unrealized built-in gain” in the assets of the corporation undergoing the ownership change.

As of December 31, 2025, we had an NOL carryforward of approximately $436 million, capital loss carryforwards of approximately $26 million and tax credits of $4 million for U.S. federal income tax purposes, principally consisting of tax attributes acquired from QEP Resources, Inc. (“QEP”), Sitio and Rattler. As a result of ownership changes for Diamondback Energy, Inc., QEP and Rattler, which occurred in connection with the acquisition of QEP and the Company’s merger with Rattler in 2022, our NOLs and other carryforwards, including those acquired from QEP and Rattler, are subject to an annual limitation under Sections 382 and 383 of the Code. Similarly, as a result of an ownership change for Sitio in connection with Viper’s Sitio Acquisition, carryforwards acquired from Sitio are subject to an annual limitation under Sections 382 and 383 of the Code.

Future changes in our stock ownership could result in an additional ownership change under Section 382 of the Code. Any such ownership change may limit our ability to offset taxable income arising after such an ownership change with NOLs or other tax attributes generated prior to such an ownership change, possibly substantially.

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 our company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws 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 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 our 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.

The provision of our certificate of incorporation and bylaws requiring exclusive venue in the Court of Chancery in the State of Delaware for certain types of lawsuits may have the effect of discouraging lawsuits against us and our directors, officers and employees.

Our certificate of incorporation and bylaws provide that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware generally shall be the sole and exclusive forum for (i) any derivative action or proceeding brought on behalf of the Company, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer or employee of the Company to the Company or its stockholders, (iii) any action asserting a claim arising pursuant to any provision of the General Corporation Law of the State of Delaware, our certificate of incorporation or bylaws or (iv) any other action asserting a claim against the Company governed by the internal affairs doctrine. This choice of forum provision does not waive our compliance with our obligations under the federal securities laws and the rules and regulations thereunder. Moreover, the provision does not apply to suits brought to enforce a duty or liability created by the Securities Exchange Act or by the Securities Act of 1933, as amended.

This choice of forum provision may increase costs to bring a claim, discourage claims or limit a stockholder’s ability to bring a claim in a judicial forum that the stockholder finds favorable for disputes with the Company or our directors, officers or employees, which may discourage such lawsuits against the Company and its directors, officers and employees, even though an action, if successful, might benefit our stockholders. Alternatively, if a court were to find the choice of forum provision to be inapplicable or unenforceable in an action, we may incur additional costs associated with resolving such matters in other jurisdictions, which could increase our costs of litigation and adversely affect our business and financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cybersecurity Risk Management Strategy

We have implemented and invested in, and will continue to implement and invest in, controls, procedures and protections (including internal and external personnel) that are designed to protect our systems, identify and remediate on a regular basis vulnerabilities in our systems and related infrastructure and monitor and mitigate the risk of data loss and other cybersecurity threats. We have engaged third-party consultants to conduct penetration testing and risk assessments. Our cybersecurity program is informed by the National Institute of Standards and Technology ("NIST") Cybersecurity Framework and measured by the Maturity and Risk Assessment Ratings associated with the NIST Cybersecurity Framework and the Capability Maturity Model Integration.

Our cybersecurity risk management program is integrated into our overall enterprise risk management program, and shares common methodologies, reporting channels and governance processes that apply across the enterprise risk management program to other legal, compliance, strategic, operational, and financial risk areas.

Our cybersecurity risk management program includes:

- risk assessments designed to help identify material cybersecurity risks to our critical systems, information, products, services, and our broader enterprise IT and operational technology, or OT, environments;
- a security team principally responsible for managing (i) our cybersecurity risk assessment processes, (ii) our security controls, and (iii) our response to cybersecurity incidents;
- the use of external service providers, where appropriate, to assess, test, train or otherwise assist with aspects of our security controls;
- security tools deployed in the IT and OT environments for protection against and monitoring for suspicious activity;
- cybersecurity awareness training of our employees, including incident response personnel and senior management;
- cybersecurity tabletop exercises for members of our cybersecurity incident response team and legal department;
- a cybersecurity incident response plan that includes procedures for responding to cybersecurity incidents; and
- a third-party risk management process for service providers, which may include diligence, assessments and/or contractual requirements, depending on each service provider's operational criticality and relative risk profile.

Cybersecurity Governance

Our cybersecurity governance program is led by the Senior Vice President and Chief Information Officer, with support from the internal information technology department. The Senior Vice President and Chief Information Officer has over 20 years of technological leadership experience in the oil and gas industry, providing oversight of all information technology disciplines, including cybersecurity, networking, infrastructure, applications, and data management and protection. The Senior Vice President and Chief Information Officer and his team, which consists of individuals who hold designations as Certified Information Systems Security Professional (CISSP), Certified Information Systems Auditor (CISA), and CompTIASecurity+, are responsible for leading enterprise-wide cybersecurity strategy, policy, standards, architecture and processes. In addition, our cybersecurity incident response team is responsible for responding to cybersecurity incidents and are guided by our Computer Security Incident Response Plan. Progress and developments in our cybersecurity governance program are communicated to members of the executive team. Our management team takes steps to remain informed about and monitor efforts to prevent, detect, mitigate and remediate cybersecurity risks and incidents through various means, which may include briefings from internal security personnel; threat intelligence and other information obtained from governmental, public or private sources, including third-party consultants engaged by us; alerts and reports produced by security tools deployed in our IT and OT environments; and through reporting by employees and service providers. While our board of directors is ultimately responsible for enterprise-wide risk oversight, the board's committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. In particular, the board's audit committee is responsible, among other things, for risk management relating to legal and regulatory requirements, including cybersecurity, which plays an integral role in our risk management strategy and continues to be an area of increasing focus for our board, the audit committee and our management team.

The audit committee of the board of directors receives quarterly updates from our Senior Vice President and Chief Information Officer on the status of our cybersecurity governance program, including as related to new or developing initiatives and any significant security incidents that may occur. Board members also receive presentations on cybersecurity topics from the Senior Vice President and Chief Information Officer as part of the board's continuing education on topics that impact public companies. Our cybersecurity governance program also includes processes to assess cybersecurity risks related to third-party service providers, suppliers and vendors.

Risks from identified cybersecurity threats have not materially affected, and are not currently anticipated to materially affect, our Company, including our business strategy, results of operations or financial condition. See, however, Item 1A. Risk Factors of this report for additional information regarding cybersecurity risks we face and their potentially material impact on our business strategy, results of operations and financial condition.

ITEM 3. LEGAL PROCEEDINGS

Diamondback has elected to use a $1 million threshold for disclosing certain environmental proceedings to which a federal, state or local governmental authority is a party.

We are a party to various routine legal proceedings, disputes and claims arising in the ordinary 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, employment claims, claims alleging violations of antitrust laws, 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, results of operations or cash flows. For additional information regarding environmental matters, see Note 15—Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data of this 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 Nasdaq under the symbol "FANG". There were 4,438 holders of record of our common stock on February 20, 2026.

Dividend Policy

In the first quarter of 2024, our board of directors approved a reduction in our return of capital commitment to our shareholders to at least 50% (down from 75%) of our quarterly Adjusted Free Cash Flow through repurchases under our share repurchase program, base dividends and variable dividends to accelerate the repayment of indebtedness incurred in connection with the Endeavor Acquisition and the Double Eagle Acquisition. Our board of directors intends to continue the payment of dividends to the holders of the Company's common stock in the future; however, the Company can provide no assurance that dividends will be authorized or declared in the future or as to the amount or type of any future dividends. Our board of directors' determination with respect to any such dividends, whether base or variable, including the record date, the payment date and the actual amount of the dividend, will depend upon our outlook for commodity prices, 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.

Recent Sales of Unregistered Securities

During the three months ended December 31, 2025, the Company issued a total of 105,607 shares of common stock as partial consideration in connection with the acquisition of certain oil and gas leases from the sellers thereof in a private transaction exempt from registration pursuant to Section 4(a)(2) of the Securities Act.

Issuer Purchases of Equity Securities

Our common stock repurchase activity for the three months ended December 31, 2025 was as follows:

Period	Total Number of Shares Purchased(1)(2)	Average Price Paid Per Share(3)(4)	Total Number of Shares Purchased as Part of Publicly Announced Plan(2)	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan(4)(5)
	(In millions, except per share amounts, shares in thousands)			
October 1, 2025 - October 31, 2025	614	$ 143.21	611	$ 3,011
November 1, 2025 - November 30, 2025	2,275	$ 151.22	2,275	$ 2,667
December 1, 2025 - December 31, 2025	18	$ 144.98	18	$ 2,665
Total	2,907	$ 149.49	2,904	

(1) Includes 3,301 shares of common stock repurchased from executives in order to satisfy tax withholding requirements. Such shares are cancelled and retired immediately upon repurchase.

(2) Includes 2.0 million shares repurchased from SGF FANG Holdings, LP ("SGF") during the fourth quarter of 2025 pursuant to a privately negotiated letter agreement dated November 28, 2025. For further discussion on the repurchase from SGF, see Note 7—Related Party Transactions in Item 8. Financial Statements and Supplementary Data of this report.

(3) The average price paid per share includes any commissions paid to repurchase stock.

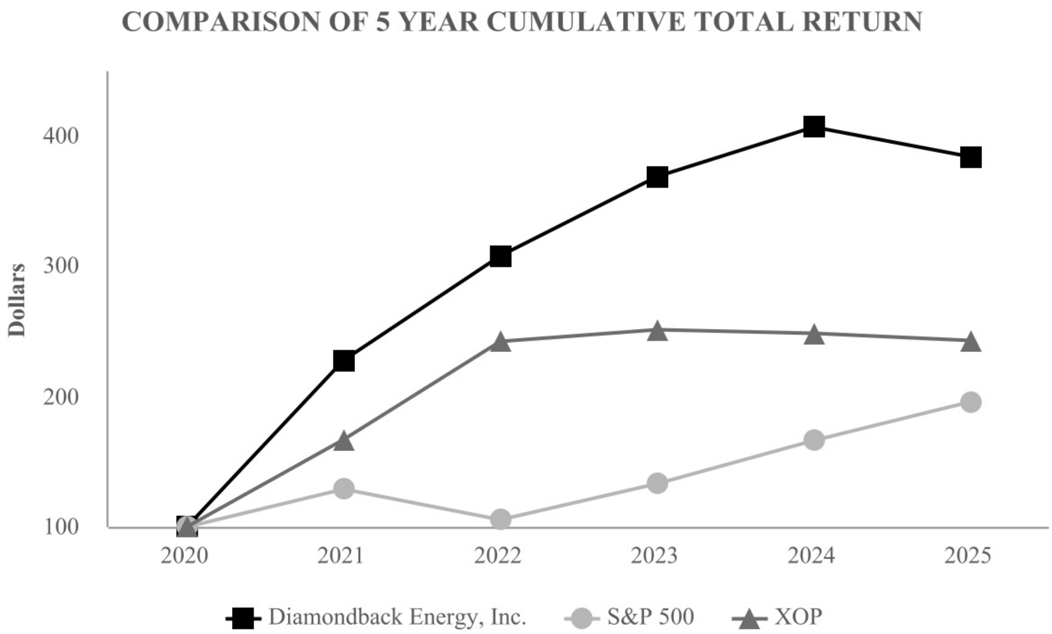
(4) In September 2021, our board of directors initiated our stock repurchase program. On July 31, 2025, our board of directors approved a $2.0 billion increase in our common stock repurchase program from $6.0 billion to $8.0 billion, excluding excise tax. The stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time.

(5) The IRA, which was enacted into law on August 16, 2022, imposed a nondeductible 1% excise tax on the net value of certain stock repurchases made after December 31, 2022. All dollar amounts presented exclude such excise taxes, as applicable.

Stock Performance Graph

The following performance graph and related information should not be deemed "soliciting material" or to be "filed" with the SEC, nor should such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate such information by reference into such a filing. The performance graph and information are included for historical comparative purposes only and should not be considered indicative of future stock performance.

The performance graph includes a comparison of our cumulative total stockholder return over a five-year period with the cumulative total returns of the Standard & Poor's 500 Stock Index, or the S&P 500, and the SPDR S&P Oil & Gas Exploration and Production ETF, or XOP. The graph assumes an investment of $100 on December 31, 2020, and that all dividends were reinvested.



	As of December 31,					
Calculated Values:	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Diamondback Energy, Inc.	$100.00	$227.44	$308.19	$368.65	$406.86	$383.98
S&P 500	$100.00	$128.68	$105.36	$133.03	$166.28	$195.98
XOP	$100.00	$166.76	$242.36	$250.96	$248.37	$243.04

ITEM 6. [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 in Item 8. Financial Statements and Supplementary Data of this 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 discussed further in Item 1A. Risk Factors and Cautionary Statement Regarding Forward-Looking Statements of this report.

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 primarily in the Permian Basin in West Texas. As of December 31, 2025, we have one reportable segment, the upstream segment. See Note 1—Description of the Business and Basis of Presentation and Note 17—Segment Information in Item 8. Financial Statements and Supplementary Data of this report for further discussion.

2025 Financial and Operating Highlights

- Recorded net income of $1.7 billion, which includes impairment of approximately $3.7 billion recorded on our proved oil and natural gas properties during the fourth quarter of 2025.
- Our cash operating costs were $10.23 per BOE, including lease operating expenses of $5.55 per BOE, cash general and administrative expenses of $0.62 per BOE and production and ad valorem taxes and gathering, processing and transportation expenses of $4.06 per BOE.
- Incurred cash capital expenditures, excluding acquisitions, of $3.5 billion.
- Paid dividends to stockholders of $1.2 billion during 2025 and declared a base cash dividend payable in the first quarter of 2026 of $1.05 per share of common stock.
- Increased our common stock repurchase program authorization to $8.0 billion, excluding excise taxes, and repurchased $2.0 billion of our common stock in 2025, leaving approximately $2.7 billion available for future repurchases at December 31, 2025.
- Issued $1.2 billion aggregate principal amount of 5.550% Senior Notes due April 1, 2035 (the "2035 Notes") to fund a portion of the cash consideration for the Double Eagle Acquisition.
- Repurchased an aggregate of approximately $455 million of our senior notes.
- Our average production was 921.0 MBOE/d.
- Drilled 463 gross horizontal wells (including 459 in the Midland Basin and 4 in the Delaware Basin).
- Turned 503 gross operated horizontal wells (including 488 in the Midland Basin and 15 in the Delaware Basin) to production.
- As of December 31, 2025, we had approximately 869,036 net acres in the Permian Basin, which primarily consisted of 774,645 net acres in the Midland Basin and 94,391 net acres in the Delaware Basin. As of December 31, 2025, we had an estimated 8,854 gross horizontal locations that we believe to be economic at $50.00 per Bbl WTI. Our publicly traded subsidiary, Viper, also owns mineral interests underlying approximately 36,004 net royalty acres in the Delaware Basin and approximately 50,595 net royalty acres in the Midland Basin. We operate approximately 35% of these net royalty acres.

Transactions and Recent Developments

Diamondback Acquisition and Divestitures

EPIC Divestiture

On October 31, 2025, we divested our 27.5% equity interest in EPIC for approximately $504 million in cash and an additional $96 million in contingent consideration (the "EPIC Divestiture"), which resulted in a gain on the sale of equity method investments of approximately $299 million. The gain is included in the caption "Other income (expense), net" on the consolidated statements of operations for the year ended December 31, 2025.

Divestiture of Water Assets to Deep Blue

On October 1, 2025, we divested EDS, a subsidiary originally acquired in connection with the Endeavor Acquisition, to our affiliate, Deep Blue Midland Basin LLC ("Deep Blue"), in exchange for upfront net cash proceeds of $694 million, subject to customary post-closing adjustments, and approximately $34 million of additional equity interests issued by Deep Blue as non-cash consideration. This transaction provides for the potential for us to earn up to an additional $200 million. If certain completion thresholds are not met, we could owe up to $150 million in contingent consideration for the years 2026 through 2028. The divestiture resulted in a gain of approximately $168 million, which is included in the caption "Other operating expenses, net" on the consolidated statements of operations for the year ended December 31, 2025. As part of the divestiture, we renewed our 15-year dedication to Deep Blue for its produced water and supply water within a 12-county area of mutual interest in the Midland Basin.

2025 Drop Down

On May 1, 2025, our wholly owned subsidiary, EER LP, divested the Endeavor Subsidiaries to Viper and Viper LLC in exchange for consideration consisting of (i) $873 million in cash including customary post-closing adjustments, and (ii) the issuance of 69.63 million Viper LLC units and an equal number of shares of Viper's Class B common stock.

Double Eagle Acquisition

On April 1, 2025, we completed the Double Eagle Acquisition for consideration of $3.1 billion in cash and approximately 6.84 million shares of our common stock, including transaction costs and certain customary post-closing adjustments. The Double Eagle Acquisition consisted of approximately 67,700 gross (40,000 net) acres, which are primarily located in the Midland Basin, and approximately 407 gross (342 net) horizontal locations in primary development targets.

Viper Acquisitions and Divestitures

Divestiture of Non-Permian Assets

On February 9, 2026, Viper completed the Viper Non-Permian Divestiture for net cash proceeds of approximately $617 million, subject to customary post-closing adjustments. The divested properties consisted of approximately 9,400 net royalty acres in the Denver-Julesburg, Eagle Ford and Williston basins with current production of approximately 4,750 BO/d. Proceeds from the Viper Non-Permian Divestiture were used to repay the Viper 2025 Term Loan (as defined below) and to reduce borrowings outstanding on the Viper Revolving Credit Facility (as defined and discussed in Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report).

Sitio Acquisition

On August 19, 2025, Viper and Viper LLC completed the Sitio Acquisition in an all-equity transaction valued at approximately $4.0 billion, including customary transaction costs and post-closing adjustments and the partial retirement of Sitio's net debt of approximately $1.2 billion. The mineral and royalty interests acquired in the Sitio Acquisition represent approximately 25,300 net royalty acres in the Permian Basin and approximately 9,000 net royalty acres in the Denver-Julesburg, Eagle Ford and Williston basins, for total acreage of approximately 34,300 net royalty acres.

See Note 4—Acquisitions and Divestitures and Note 16—Subsequent Events in Item 8. Financial Statements and Supplementary Data of this report for further discussion of the acquisitions and divestitures discussed above.

Diamondback Capital Transactions

2025 Term Loan Agreement

In connection with the Double Eagle Acquisition, Diamondback Energy, Inc., as guarantor, entered into a term loan credit agreement with Diamondback E&P, as borrower, and Bank of America, N.A., as administrative agent (the "2025 Term Loan"). The 2025 Term Loan provided the Company with the ability to borrow up to $1.5 billion, which we drew in a single borrowing to fund a portion of the cash consideration for the Double Eagle Acquisition.

2035 Notes Offering

On March 20, 2025, we issued the 2035 Notes for net proceeds of $1.2 billion, after underwriters' discounts and transaction costs, which we used to fund a portion of the cash consideration for the Double Eagle Acquisition.

Diamondback Retirement of Notes

During the year ended December 31, 2025, we opportunistically repurchased an aggregate principal amount of $455 million of our senior notes in open market transactions for total cash consideration, including accrued interest paid, of approximately $363 million, at an average of 79.3% of par value.

Viper Capital Transactions

Viper 2025 Notes Offering and Retirement of Notes

On July 23, 2025, Viper LLC issued $1.6 billion in aggregate principal amount of senior notes consisting of (i) $500 million aggregate principal amount of 4.900% Senior Notes due August 1, 2030 (the "Viper 2030 Notes"), and (ii) $1.1 billion aggregate principal amount of 5.700% Senior Notes due August 1, 2035 (the "Viper 2035 Notes" and together with the Viper 2030 Notes, the "Viper 2025 Notes"). Viper used approximately $824 million of the net proceeds from the issuance of the Viper 2025 Notes to redeem all of Viper's 7.375% Senior Notes maturing on November 1, 2031 (the "Viper 2031 Notes"), and on November 1, 2025, Viper redeemed all of their 5.375% Senior Notes due 2027 (the "Viper 2027 Notes"), including accrued and unpaid interest through the date of redemption and any redemption premiums. Viper used the remaining net proceeds to partially retire Sitio's net debt of approximately $1.2 billion including any fees, costs and expenses related to the redemption or repayment of such debt, and for general corporate purposes. On December 23, 2025, Viper Energy Partners LLC converted its legal form (the "Viper LLC Conversion"), in accordance with the applicable laws of the State of Delaware, to a Delaware limited partnership named Viper Energy Partners LP ("Viper LP"), which is now the issuer under the Viper 2025 Notes.

Viper 2025 Term Loan

On July 23, 2025, Former Viper, as guarantor, Viper LLC, as borrower, and Goldman Sachs Bank USA, as administrative agent, entered into a $500 million term loan credit agreement (the "Viper 2025 Term Loan"), which was fully drawn to partially fund the retirement of Sitio's net debt. Following the closing of the Sitio Acquisition, New Viper became an additional guarantor of the borrower's obligations under the Viper 2025 Term Loan. Further, after the Viper LLC Conversion, Viper LP, as successor to Viper Energy Partners LLC, became the borrower with respect to the Viper 2025 Term Loan. The Viper 2025 Term Loan was repaid in full in February 2026.

Viper 2025 Equity Offering

On February 3, 2025, Viper completed an underwritten public offering of approximately 28.34 million shares of its Class A common stock, which included approximately 3.70 million shares issued pursuant to an option to purchase additional shares of its Class A common stock granted to the underwriters at a price to the public of $44.50 per share, for total net proceeds to Viper of approximately $1.2 billion, after the underwriters' discount and transaction costs (the "Viper 2025 Equity Offering").

See Note 8—Debt and Note 9—Stockholders' Equity and Earnings (Loss) Per Share in Item 8. Financial Statements and Supplementary Data of this report for further discussion of the capital transactions above.

Commodity Prices

Prices for oil, natural gas and natural gas liquids are determined primarily by prevailing market conditions. Regional and worldwide economic activity, changes in trade or other government policies or regulations, including with respect to U.S. energy and monetary policies, tariffs or other trade barriers and any resulting trade tensions, regional conflicts and political instability, extreme weather conditions and other substantially variable factors, influence market conditions for these products. These factors are beyond our control and are difficult to predict. During 2025, 2024 and 2023, WTI prices averaged $64.73, $75.76 and $77.60 per Bbl, respectively, and Henry Hub prices averaged $3.62, $2.41 and $2.66 per MMBtu, respectively.

Given the overall decline in SEC Prices through 2025 as compared to 2024, we believe a material non-cash impairment of our assets is reasonably likely to occur in the first quarter of 2026. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties, income tax rate assumptions and other factors will determine our actual ceiling test calculation and impairment analysis in future periods. Based on the number of factors that may impact our future estimate of proved reserves, we are currently unable to determine an estimate of the amount or range of amounts of any potential impairment charge in the first quarter of 2026. Impairment charges affect our results of operations but do not reduce our cash flow.

For additional information around risks related to commodity prices, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.

Outlook

Our cash capital expenditures for 2025 were consistent with our guidance presented in November 2025. Given the soft outlook for oil prices currently, our 2026 plan is to keep activity and production essentially flat relative to our fourth quarter 2025 levels at approximately 926 MBOE/d to 962 MBOE/d, as adjusted for the impact of the Viper Non-Permian Divestiture. We have currently budgeted 2026 total cash capital spend of $3.60 billion to $3.90 billion, which at the midpoint is an increase of 7% from our 2025 cash capital budget. In 2026, we will continue to target an industry-leading breakeven oil price by capturing incremental technical and operational efficiencies, driving higher margins and maximizing Adjusted Free Cash Flow to fund our dividend, opportunistically repurchase shares, and continue strengthening the balance sheet.

Our board of directors has approved a return of capital commitment to our shareholders of at least 50% of our quarterly Adjusted Free Cash Flow. We exceeded our commitment to sell at least $1.5 billion of non-core assets during 2025 to help accelerate debt reduction and maintain a strong balance sheet. We also remain focused on our long-term priority to return cash to our stockholders.

In 2025, we successfully delineated the Barnett/Woodford zone across our Midland Basin acreage, confirming reservoir continuity and improving our development line of sight, which will add meaningful incremental drilling locations to our inventory. As a result, we plan to allocate approximately 3% to 4% of our 2026 total capital budget to further advance the Barnett/Woodford across our acreage.

As of December 31, 2025, we were operating 15 drilling rigs and four completion crews and currently intend to operate between 15 and 18 drilling rigs and approximately five completion crews in 2026 on average across our current acreage position in the Midland and Delaware Basins.

Results of Operations

For a discussion of the results of operations for the year ended December 31, 2024 as compared to the year ended December 31, 2023, 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, 2024 (filed with the SEC on February 26, 2025), which is incorporated in this report by reference from such prior report on Form 10-K.

Comparison of the Years Ended December 31, 2025 and 2024

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

	Year Ended December 31,	
	2025	**2024**
Revenues (in millions):		
Oil sales	$ 11,621	$ 9,067
Natural gas sales	400	89
Natural gas liquid sales	1,432	944
Total oil, natural gas and natural gas liquid revenues	$ 13,453	$ 10,100
Production Data:		
Oil (MBbls)	181,462	123,325
Natural gas (MMcf)	447,855	275,680
Natural gas liquids (MBbls)	80,073	49,700
Combined volumes (MBOE)(1)	336,178	218,972
Daily oil volumes (BO/d)	497,156	336,954
Daily combined volumes (BOE/d)	921,036	598,284
Average Prices:		
Oil ($ per Bbl)	$ 64.04	$ 73.52
Natural gas ($ per Mcf)	$ 0.89	$ 0.32
Natural gas liquids ($ per Bbl)	$ 17.88	$ 18.99
Combined ($ per BOE)	$ 40.02	$ 46.12
Oil, hedged ($ per Bbl)(2)	$ 63.14	$ 72.68
Natural gas, hedged ($ per Mcf)(2)	$ 1.84	$ 0.91
Natural gas liquids, hedged ($ per Bbl)(2)	$ 17.88	$ 18.99
Average price, hedged ($ per BOE)(2)	$ 40.79	$ 46.38

(1) Bbl equivalents are calculated using a conversion rate of six Mcf per Bbl.
(2) 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 table provides information on the mix of our production for the periods indicated:

	Year Ended December 31,	
	2025	2024
Oil (MBbls)	54 %	56 %
Natural gas (MMcf)	22 %	21 %
Natural gas liquids (MBbls)	24 %	23 %
	100 %	100 %

See Items 1 and 2. Business and Properties—Oil and Natural Gas Data—Oil and Natural Gas Production and Price History of this report for further discussion of production by basin.

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.

Our oil, natural gas and natural gas liquids revenues increased by approximately $3.4 billion, or 33%, to $13.5 billion in 2025 compared to 2024. This net increase consisted of an additional $4.9 billion attributable to the 54% growth in our combined production volumes, partially offset by a net reduction of $1.6 billion primarily due to lower average prices received for our oil production.

Approximately 42% of the growth in our combined production volumes is attributable to new wells added between periods, 41% of the increase is attributable to the Endeavor Acquisition and 12% is attributable to the Double Eagle Acquisition.

See Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report for further discussion of the Endeavor Acquisition and the Double Eagle Acquisition.

Net Sales of Purchased Oil. We enter into purchase transactions with third parties and separate sale transactions with third parties to satisfy certain of our unused oil pipeline capacity commitments.

The following table presents the net sales of purchased oil from third parties for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Sales of purchased oil	$ 1,476	$ 923
Purchased oil expense	1,474	921
Net sales of purchased oil	$ 2	$ 2

Other Revenues. The following table shows the other revenues for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Other operating income	$ 97	$ 43

Other operating income increased by $54 million in 2025 compared to 2024 primarily due to (i) a $35 million increase in midstream revenues attributable to assets acquired in the Endeavor Acquisition, and (ii) a $19 million increase in lease bonus income received during 2025.

Lease Operating Expenses. The following table shows lease operating expenses for the periods indicated:

	Year Ended December 31,			
	2025		2024	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Lease operating expenses	$ 1,865	$ 5.55	$ 1,286	$ 5.87

Lease operating expenses increased by $579 million in 2025 compared to 2024. The increase primarily consists of (i) $368 million of costs associated with operating wells acquired in the Endeavor Acquisition and the Double Eagle Acquisition, (ii) $114 million in additional well workover, artificial lift, maintenance and utility costs, (iii) $66 million of additional costs related to higher legacy production volumes, (iv) $23 million in additional expense due to an increase in our average working interest, and (v) other individually insignificant changes. Currently, we estimate expenditures for lease operating expenses may range between approximately $2.0 billion and $2.2 billion in 2026 at the midpoint of expected production.

Production and Ad Valorem Tax Expense. The following table shows production and ad valorem tax expense for the periods indicated:

	Year Ended December 31,					
	2025			2024		
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Percentage of Oil, Natural Gas and Natural Gas Liquids Revenue**	**Amount**	**Per BOE**	**Percentage of Oil, Natural Gas and Natural Gas Liquids Revenue**
Production taxes	$ 634	$ 1.89	4.7 %	$ 462	$ 2.11	4.6 %
Ad valorem taxes	217	0.64	1.6	176	0.80	1.7
Total production and ad valorem expense	$ 851	$ 2.53	6.3 %	$ 638	$ 2.91	6.3 %

In general, production taxes are directly related to production revenues and are based upon current year commodity prices and ad valorem taxes are based, among other factors, on property values driven by prior year commodity prices. For 2025 compared to 2024, both production taxes and ad valorem taxes as a percentage of oil, natural gas and natural gas liquids revenues remained relatively flat. Rates per BOE for both production taxes and ad valorem taxes declined primarily due to the increase in production volumes for 2025 compared to 2024.

Gathering, Processing and Transportation Expense. The following table shows gathering, processing and transportation expense for the periods indicated:

	Year Ended December 31,			
	2025		2024	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Gathering, processing and transportation	$ 515	$ 1.53	$ 356	$ 1.63

Gathering, processing and transportation expense increased by $159 million in 2025 compared to 2024 primarily due to (i) $54 million incurred on additional production acquired in the Endeavor Acquisition, (ii) an additional $44 million in transportation costs incurred to meet our minimum volume commitments on certain pipelines, (iii) $34 million associated with production from new wells completed between 2025 and 2024, (iv) $18 million related to new firm transportation contracts that became effective during 2025, and (v) other individually insignificant changes. Currently, we estimate expenditures for gathering, processing and transportation may range between approximately $507 million and $597 million in 2026 at the midpoint of expected production.

Depreciation, Depletion, Amortization and Accretion. The following table shows the components of our depreciation, depletion and amortization expense for the periods indicated:

	Year Ended December 31,	
(In millions, except BOE amounts)	**2025**	**2024**
Depletion of proved oil and natural gas properties	$ 4,908	$ 2,759
Depreciation of other property and equipment	86	61
Other amortization	9	8
Asset retirement obligation accretion	35	22
Depreciation, depletion, amortization and accretion expense	$ 5,038	$ 2,850
Oil and natural gas properties depletion rate per BOE	$ 14.60	$ 12.60
Depreciation, depletion, amortization and accretion per BOE	$ 14.99	$ 13.02

The increase in depletion of proved oil and natural gas properties of $2.1 billion in 2025 as compared to 2024 consists primarily of $1.5 billion from growth in production volumes and $672 million due to an increase in the depletion rate resulting largely from the addition of higher value leasehold costs and proved reserves from the Endeavor Acquisition, the Double Eagle Acquisition and, to a lesser extent, Viper's Sitio Acquisition and Viper's Tumbleweed Acquisitions (as defined and discussed in Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report).

Impairment of Oil and Natural Gas Properties. The following table shows impairment of oil and natural gas properties for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Impairment of oil and natural gas properties	$ 3,652	$ —

The non-cash ceiling test impairment charge of $3.7 billion for the year ended December 31, 2025 primarily resulted from the decline in SEC Prices during 2025. Impairment charges affect our results of operations but do not reduce our cash flow.

In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties, income tax rate assumptions and other factors will determine our actual ceiling test calculation and impairment analysis in future periods. If the trailing 12-month commodity prices fall as compared to the commodity prices used in prior quarters, we may have material write-downs in subsequent quarters. Given the overall decline in SEC Prices from the first quarter of 2025 through the first two months of 2026, we believe an additional material non-cash impairment of our assets is reasonably likely to occur in the first quarter of 2026; however, based on the number of factors that may impact our future estimate of proved reserves, we are currently unable to determine an estimate of the amount or range of amounts of any potential impairment charge in the first quarter of 2026.

General and Administrative Expenses. The following table shows the components of general and administrative expenses for the periods indicated:

	Year Ended December 31,			
	2025		**2024**	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
General and administrative expenses	$ 207	$ 0.62	$ 148	$ 0.68
Non-cash stock-based compensation	81	0.24	65	0.30
Total general and administrative expenses	$ 288	$ 0.86	$ 213	$ 0.98

The increase in general and administrative expenses of $59 million in 2025 compared to 2024 was primarily due to a $47 million increase in employee compensation and benefit costs related to increasing headcount largely from the Endeavor Acquisition for the full year of 2025 and other individually insignificant items.

Other Operating Expenses. The following table shows other operating expenses for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Other operating expenses, net	$ 77	$ 406

Other operating expenses decreased by $329 million in 2025 compared to 2024 primarily due to (i) a $198 million reduction in merger and transaction costs largely due to 2024 including $303 million in costs associated with the Endeavor Acquisition compared to $105 million of costs incurred in 2025 for transactions including the 2025 Drop Down, Viper's Sitio Acquisition and additional severance and other costs for the Endeavor Acquisition, (ii) a $168 million gain on the sale of our EDS subsidiary during the fourth quarter of 2025, and (iii) other individually insignificant expenses. These decreases were partially offset by a $38 million increase in midstream costs incurred in connection with EDS prior to its sale in the fourth quarter of 2025.

Derivative Instruments. The following table shows the net gain (loss) on derivative instruments and the net cash received (paid) on settlements of derivative instruments for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Gain (loss) on derivative instruments, net	$ 341	$ 137
Net cash received (paid) on settlements[(1)]	$ 181	$ (51)

(1) Includes cash paid on interest rate swaps terminated prior to their contractual maturity of $67 million for 2025 and $37 million for 2024.

The increase in gain on derivative instruments for the year ended December 31, 2025, compared to the same period in 2024 primarily reflects (i) a $118 million net gain on natural gas contracts, which was comprised of a $262 million increase in cash received on the settlement of contracts partially offset by a $144 million decrease in the value of our unsettled natural gas contracts primarily due to an increase in market prices for natural gas compared to our contract prices, (ii) an $89 million gain on our interest rate swaps, which was comprised of a $59 million increase in the value of our unsettled interest rate swap contracts primarily due to a decline in expected future interest rates and the early termination of $600 million in notional amount of the interest rate swaps in 2025 and a $30 million net decrease in cash paid for the settlement and early termination of our interest rate derivatives and treasury locks, and (iii) other individually insignificant changes.

See Note 12—Derivatives in Item 8. Financial Statements and Supplementary Data of this report for further details regarding our derivative instruments and interest rate swaps.

Other Income (Expense). The following table shows other income and expenses for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Interest expense, net	$ (244)	$ (135)
Other income (expense), net	$ 455	$ 101
Gain (loss) on extinguishment of debt	$ 56	$ 2

Interest expense, net increased by $109 million in 2025, compared to 2024. This increase primarily consisted of (i) a $131 million reduction in interest income (which reduces interest expense) attributable to holding funds raised for the Endeavor Acquisition in cash in short-term interest bearing accounts during the year ended December 31, 2024, (ii) $111 million of interest expense on the 2025 Term Loan and 2035 Notes, which were both issued in March 2025, (iii) $91 million of additional interest expense on the April 2024 Notes, and (iv) a net $31 million increase related to Viper comprised of additional interest expense on the Viper 2025 Notes and Viper 2025 Term Loan partially offset by a reduction in interest expense attributable to Viper's redemption of the Viper 2027 Notes and the Viper 2031 Notes. These increases were partially offset by (i) a $237 million increase in capitalized interest costs, which reduces interest expense, (ii) a $24 million reduction in amortization of debt issuance costs primarily related to fully amortizing costs related to our bridge facility in 2024 upon its termination, and (iii) other individually insignificant offsetting changes. Currently, we estimate expenditures for interest expense, net may range between approximately $237 million and $316 million in 2026.

See Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report for further details regarding outstanding borrowing, interest expense and gain (loss) on extinguishment of debt.

Other income for the year ended December 31, 2025, increased by $354 million compared to the same period in 2024, primarily due to an increase of $363 million in the gain recognized on the sale of various equity method investments in 2025 compared to 2024. This net gain was partially offset by a $30 million decrease in the value of an investment recorded at fair value during 2025, compared to 2024 and other individually insignificant items.

Provision for (Benefit from) Income Taxes. The following table shows the provision for (benefit from) income taxes for the periods indicated:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Provision for (benefit from) income taxes	$ 327	$ 800

The reduction in our income tax provision for 2025 compared to 2024 was primarily due to the decrease in pre-tax income resulting largely from the non-cash ceiling test impairment recognized in 2025. See Note 11—Income Taxes in Item 8. Financial Statements and Supplementary Data of this report for further discussion of our income tax expense.

Liquidity and Capital Resources

Overview of Sources and Uses of Cash

Historically, our primary sources of liquidity have included cash flows from operations, proceeds from our public equity offerings, borrowings under our revolving credit facility and term loan agreements, proceeds from the issuance of senior notes and sales of non-core assets. Our primary uses of capital have been for the acquisition, development and exploration of oil and natural gas properties, repayment of debt and returning capital to stockholders. At December 31, 2025, we had approximately $2.6 billion of liquidity consisting of $91 million in standalone cash and cash equivalents and $2.5 billion available under our credit facility. As discussed below, our cash capital budget guidance for 2026 is approximately $3.60 billion to $3.90 billion, which prioritizes free cash flow generation and debt reduction. As of December 31, 2025, we had approximately $763 million of senior notes maturing in the next 12 months.

Future cash flows are subject to a number of variables, including the level of our oil and natural gas production and the volatility of commodity prices. Further, significant additional capital expenditures will be required to more fully develop our properties. Prices for our commodities are determined primarily by prevailing market conditions, regional and worldwide economic activity, weather and other substantially variable factors. These factors are beyond our control and are difficult to predict. See Item 1A. Risk Factors of this report above. In order to mitigate this volatility, we enter into derivative contracts with a number of financial institutions, all of which are participants in our credit facility, to economically hedge a portion of our estimated future crude oil and natural gas production as discussed further in Note 12—Derivatives in Item 8. Financial Statements and Supplementary Data and Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk of this report. The level of our hedging activity and duration of the financial instruments employed depend on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

Cash Flow

Our cash flows for the years ended December 31, 2025 and 2024 are presented below:

	Year Ended December 31,	
	2025	**2024**
	(In millions)	
Net cash provided by (used in) operating activities	$ 8,758	$ 6,413
Net cash provided by (used in) investing activities	(7,809)	(11,221)
Net cash provided by (used in) financing activities	(1,007)	4,387
Net change in cash	$ (58)	$ (421)

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.

The increase in operating cash flows for the year ended December 31, 2025 compared to the same period in 2024 primarily resulted from (i) $3.4 billion in additional revenue, excluding sales of purchased oil, and (ii) an increase of $232 million of cash received on settlements of derivatives in 2025 compared to cash paid on settlements of derivatives in 2024, and a reduction of $114 million in cash paid for interest, net of capitalized amounts. These cash inflows were partially offset by (i) higher cash operating expenses, excluding purchased oil expense, of approximately $483 million, (ii) an increase of $629 million in cash paid for taxes, and (iii) fluctuations in other working capital balances due primarily to the timing of when collections were made on accounts receivable and payments were made on accounts payable. See "—*Results of Operations*" for discussion of significant changes in our revenues and expenses.

Investing Activities

The majority of our net cash used in investing activities during the year ended December 31, 2025, was for drilling and completion costs in conjunction with our development program as well as the acquisition of properties and equipment for the Double Eagle Acquisition and Viper's Sitio Acquisition. The majority of our net cash used in investing activities during the year ended December 31, 2024, was for the Endeavor Acquisition. These cash outflows were partially offset by proceeds received from the divestitures of various oil and gas properties and other assets including EDS and the EPIC Divestiture, which are discussed further in Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this 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,	
	2025	2024
	(In millions)	
Operated drilling and completion additions to oil and natural gas properties	$ (2,951)	$ (2,617)
Capital workovers, non-operated additions to oil and natural gas properties and science	(335)	(15)
Infrastructure, environmental and midstream additions	(237)	(235)
Total	$ (3,523)	$ (2,867)

For further discussion regarding our development program, please see Items 1 and 2. Business and Properties—Oil and Natural Gas Data—Wells Drilled and Completed in 2025 of this report.

Financing Activities

During the year ended December 31, 2025, net cash used in financing activities was primarily attributable to (i) $2.2 billion of repurchases as part of our and Viper's repurchase programs, (ii) $1.9 billion to repay and retire our Tranche A Loans and partially repay the 2025 Term Loan, (iii) $1.2 billion of dividends paid to stockholders, (iv) $1.2 billion paid for the retirement of certain of our and Viper's senior notes, (v) $382 million in dividends paid to non-controlling interest, (vi) and various other individually insignificant costs. These cash outflows were partially offset by (i) $2.8 billion of proceeds from the issuance of the 2035 Notes and Viper 2025 Notes, (ii) $2.0 billion of aggregate proceeds from the 2025 Term Loan and the Viper 2025 Term Loan, (iii) $1.2 billion in proceeds from the Viper 2025 Equity Offering, and (iv) $156 million in borrowings on our credit facilities, net of repayments.

During the year ended December 31, 2024, net cash provided by financing activities was primarily attributable to (i) $5.5 billion of proceeds from the issuance of the April 2024 Notes, (ii) $900 million in borrowings on our Tranche A Loans, net of repayments, (iii) $476 million in proceeds from the Viper 2024 Equity Offering (as defined and discussed in Note 9—Stockholders' Equity and Earnings (Loss) Per Share in Item 8. Financial Statements and Supplementary Data of this report), (iv) $451 million in proceeds from the sale of our shares of Viper's Class A common stock, and (v) $2 million in borrowings on our credit facilities, net of repayments. These cash inflows were partially offset by (i) $1.6 billion of dividends paid to stockholders, (ii) $959 million of repurchases as part of our and Viper's share repurchase programs, (iii) $227 million in distributions to non-controlling interest, (iv) $99 million of debt issuance costs primarily associated with the April 2024 Notes and Tranche A Loans, and (v) $39 million in cash paid for tax withholdings on vested employee stock awards.

Capital Resources

Our working capital requirements are primarily supported by our cash and cash equivalents and available borrowings under our revolving credit facility. We may draw on our revolving credit facility to meet short-term cash requirements, or issue debt or equity securities as part of our longer-term liquidity and capital management program. Because of the alternatives available to us, we believe that our short-term and long-term liquidity are adequate to fund not only our current operations, but also our near-term and long-term capital requirements.

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. Any prolonged volatility in the capital, financial and/or credit 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.

Revolving Credit Facilities

Diamondback's Credit Agreement

As of December 31, 2025, the maximum credit amount available under our undrawn revolving credit facility was $2.5 billion, which may be increased to a total maximum commitment amount of $2.6 billion and has a maturity date of June 12, 2030.

Viper's Revolving Credit Facility

In 2025, Former Viper, as guarantor, entered into a credit agreement with Viper LLC, as borrower, and Wells Fargo, as the administrative agent (the "Viper Revolving Credit Facility"), which matures on June 12, 2030, and provides for a commitment amount of $1.5 billion. As of December 31, 2025, the Viper Revolving Credit Facility had $105 million in outstanding borrowings and $1.4 billion available for future borrowings. Following the Viper LLC Conversion, Viper LP, as successor to Viper Energy Partners LLC, became the borrower with respect to the Viper Revolving Credit Facility.

For additional discussion of our outstanding debt as of December 31, 2025, see Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report.

Debt Ratings

We receive debt ratings from the major ratings agencies in the U.S which impact the interest rates we receive on our variable rate debt and interest rate swaps. In determining our debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, commodity pricing levels, our liquidity, asset quality, reserve mix, debt levels, cost structure, planned asset sales and production growth opportunities. Currently, our credit ratings from the three main credit rating agencies are as follows:

- Standard and Poor's Global Ratings Services (BBB);
- Fitch Investor Services (BBB+); and
- Moody's Investor Services (Baa2).

Any rating downgrades may result in additional letters of credit or cash collateral being posted under certain contractual arrangements.

Capital Requirements

In addition to future operating expenses and working capital commitments discussed in "—*Outlook*," our primary short and long-term liquidity requirements consist primarily of (i) capital expenditures, (ii) payments of principal and interest on our revolving credit facility, 2025 Term Loan and senior notes, (iii) payments of other contractual obligations, and (iv) cash used to pay for dividends and repurchases of securities.

2026 Capital Spending Plan

We currently estimate that our 2026 cash capital budget will be $3.60 billion to $3.90 billion, which includes $3.05 billion to $3.27 billion for operated horizontal drilling and completions.

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 will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence and our capital expenditure budget up or down in response to changes in commodity prices and overall market conditions.

Payments of Principal and Interest on Debt Instruments

As of December 31, 2025, our debt, including the debt of Viper, consisted of approximately $13.5 billion in aggregate outstanding principal amount of senior notes, $550 million outstanding under the 2025 Term Loan due in 2027, $500 million outstanding under the Viper 2025 Term Loan due in 2027, which was repaid in February 2026, and $105 million in outstanding borrowings under the Viper Revolving Credit Facility, which was repaid in the first quarter of 2026.

At December 31, 2025, we have total principal payments due on our outstanding senior notes, including those of Viper, of $763 million in 2026, $850 million in 2027, $73 million in 2028, $915 million in 2029, $1.4 billion in 2030 and $9.6 billion thereafter. Additionally, we expect to incur future cash interest costs on these senior notes of approximately $693 million in 2026, $1.3 billion cumulatively in the years from 2027 through 2028, $1.2 billion cumulatively in the years from 2029 and 2030, and $6.8 billion cumulatively between 2031 and 2064.

See Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report for further details regarding our outstanding borrowing and interest expense.

Other Contractual Obligations and Commitments

At December 31, 2025, our other significant contractual obligations consist primarily of (i) minimum transportation commitments totaling $3.0 billion, (ii) electrical power purchase commitments totaling $495 million, (iii) asset retirement obligations totaling $542 million, (iv) electric fracturing fleet and related power generation services commitments totaling $124 million, (v) compressor rental commitments totaling $90 million, and (vi) minimum purchase commitments for quantities of sand used in our drilling operations totaling $56 million. We expect to make aggregate payments of approximately $586 million for these commitments during 2026. See Note 6—Asset Retirement Obligations and Note 15—Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data of this report for further discussion of these and other contractual obligations and commitments.

We and Five Point Energy LLC currently anticipate collectively contributing $500 million in follow-on capital to fund future growth in our Deep Blue Midland Basin LLC joint venture projects and acquisitions.

Return of Capital Commitment

Our board of directors has approved a return of capital commitment of at least 50% of our quarterly Adjusted Free Cash Flow to our stockholders through repurchases under our share repurchase program, base dividends and variable dividends. The remainder of our Adjusted Free Cash Flow will be used primarily to reduce debt. On February 19, 2026, our board of directors declared a base cash dividend for the fourth quarter of 2025 of $1.05 per share of common stock.

Future base and variable dividends are at the discretion of our board of directors, and the board of directors may change the dividend amount from time to time based on our outlook for commodity prices, liquidity, debt levels, capital resources, Adjusted Free Cash Flow and other factors. We can provide no assurance that dividends will be authorized or declared in the future or as to the amount and type of any future dividends. Any future dividends, whether base or variable, if declared and paid, will by their nature fluctuate based on our free cash flow, which will depend on a number of factors beyond our control, including commodity prices.

On July 31, 2025, our board of directors approved an increase in our common stock repurchase program from $6.0 billion to $8.0 billion, excluding the 1% U.S. federal excise tax on certain repurchases of stock by publicly traded U.S. corporations enacted as part of the IRA. Since the inception of the stock repurchase program through February 20, 2026, we have repurchased an aggregate 40.69 million shares of our common stock for a total cost of $5.7 billion, which includes $637 million for the repurchase of 4.0 million shares from SGF, excluding excise tax, leaving approximately $2.3 billion for future repurchases under such stock repurchase program. Subject to regulatory restrictions and other factors discussed elsewhere in this report, we intend to continue to purchase shares under this repurchase program opportunistically with available funds primarily from cash flow from operations and liquidity events such as the sale of assets while maintaining sufficient liquidity to fund our capital expenditure programs; however, the stock repurchase program is at the discretion of our board of directors and can be amended, terminated or suspended at any time. Repurchases may be executed in privately negotiated or open-market transactions, consistent with Rule 10b-18 under the Securities Exchange Act of 1934 and other applicable requirements. All shares repurchased will be retired. See Note 9—Stockholders' Equity and Earnings (Loss) Per Share in Item 8. Financial Statements and Supplementary Data of this report for further discussion of our stock repurchase program.

Guarantor Financial Information

Diamondback E&P is the sole guarantor under the indentures governing the outstanding Guaranteed 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 indentures governing the Guaranteed Senior Notes, such as, with certain exceptions, (i) in the event Diamondback E&P (or all or substantially all of its assets) is sold or disposed of, (ii) in the event Diamondback E&P ceases to be a guarantor of or otherwise be an obligor under certain other indebtedness, and (iii) in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the relevant indenture.

Diamondback E&P's guarantees of the Guaranteed 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 Guaranteed Senior Notes against Diamondback E&P 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 E&P'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 E&P. 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 E&P, 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.

	December 31, 2025	
Summarized Balance Sheets:	**(In millions)**	
Assets:		
Current assets	$	844
Property and equipment, net	$	19,670
Other noncurrent assets	$	142
Liabilities:		
Current liabilities	$	3,304
Intercompany accounts payable, non-guarantor subsidiary	$	6,970
Long-term debt	$	11,540
Other noncurrent liabilities	$	2,186

Summarized Statement of Operations:		Year Ended December 31, 2025 (In millions)
Revenues	$	6,765
Income (loss) from operations[(1)]	$	(1,296)
Net income (loss)	$	(1,001)

(1) During the year ended December 31, 2025, the Company recorded a significant noncash impairment that is reflected in the summarized results of the guarantor group. This impairment is not indicative of cash flows available for debt service.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations is 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 and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates and assumptions on a regular basis. Critical accounting estimates are those estimates made in accordance with generally accepted accounting principles that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on the financial condition or results of operations of the registrant. 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.

We consider the following to be our most critical accounting estimates and have reviewed these critical accounting estimates with the Audit Committee of our board of directors.

Oil and Natural Gas Accounting and Reserves

We account for our oil and natural gas producing activities using the full cost method of accounting, which is dependent on the estimation of proved reserves to determine the rate at which we record depletion on our oil and natural gas properties and whether the value of our evaluated oil and natural gas properties is permanently impaired based on the quarterly full cost ceiling impairment test. Further, we utilize estimated proved reserves to assign fair value to acquired proved oil and natural gas properties including mineral and royalty interests. As such, we consider the estimation of proved reserves to be a critical accounting estimate.

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. Proved oil and natural gas reserve estimates and their associated future net cash flows were prepared by our internal reservoir engineers and audited by Ryder Scott Company, L.P., independent petroleum engineers, as of December 31, 2025, 2024 and 2023. 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. Significant inputs included in the calculation of future net cash flows include our estimate of operating and development costs, anticipated production of proved reserves and other relevant 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, and reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Although every reasonable effort is made to ensure that reported reserve estimates 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 depletion of capitalized costs and result in impairment of assets that may be material. Revisions of previous reserve estimates accounted for approximately $4.2 billion, or 143% of the net change in the standardized measure of our total reserves from December 31, 2024 to December 31, 2025. The Company recorded a material impairment during the year ended December 31, 2025 as discussed in Note 5—Property and Equipment in Item 8. Financial Statements and Supplementary Data of this report. No impairments were recorded for our proved oil and gas properties during the years ended December 31, 2024 and 2023. Based on the historical 12-month average trailing SEC prices for oil and natural gas throughout 2025 and into 2026, we are currently projecting a material full cost ceiling impairment in the first quarter of 2026. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties, income tax rate assumptions and other factors will determine our actual ceiling test calculation and impairment analysis in future periods. Based on the number of factors that may impact our future estimate of proved reserves, we are currently unable to determine an estimate of the amount or range of amounts of any potential impairment charge in the first quarter of 2026. Impairment charges affect our results of operations but do not reduce our cash flow.

Additionally, 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 individual basis or as a group if properties are individually insignificant) at least annually for possible impairment. This assessment is subjective and includes consideration of the following factors, among others: (i) intent to drill, (ii) remaining lease term, (iii) geological and geophysical evaluations, (iv) drilling results and activity, (v) the assignment of proved reserves, and (vi) the economic viability of development if proved reserves are assigned. At December 31, 2025, our unevaluated properties totaled $23.9 billion, which consisted of 408,284 net undeveloped leasehold acres with approximately 10,902 net acres set to expire in 2026 if no action is taken to develop or extend. We had no significant impairment losses on our unevaluated properties during the year ended December 31, 2025, but any such future impairment could potentially be material to our consolidated financial statements.

Business Combinations

We account for business combinations in which it has been determined we are the acquirer using the acquisition method of accounting. Accordingly, identifiable assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. Fair value estimates are determined based on information that existed at the time of the acquisition, utilizing expectations and assumptions that would be available to and made by a market participant. When market-observable prices are not available to value assets and liabilities, the Company may use the cost, income, or market valuation approaches depending on the quality of information available to support management’s assumptions.

The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. The assumptions made in performing these valuations include future production volumes, future commodity prices and costs, future operating and development activities, projections of oil and gas reserves and a weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of natural gas and oil properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties. Changes in key assumptions may cause the acquisition accounting to be revised, including the recognition of goodwill or discount on an acquisition. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected. See Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report for further discussion of the estimated fair value of assets acquired and liabilities assumed in business combinations including any significant changes in these estimates from the date of acquisition.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings.

Income Taxes

The amount of income taxes we record requires interpretations of complex rules and regulations of federal, state, and local 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 (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 after considering all positive and negative evidence available concerning the realizability of our deferred tax assets. Positive evidence may include forecasts of future taxable income, assessment of future business assumptions and any applicable tax planning strategies available to the

Company. Negative evidence may include losses in recent years, if any, or the projection of losses in future periods. The assessment of the realizability of our deferred tax assets, including the assessment of whether a valuation allowance is required, entails that we make estimates of, and assumptions about, future events, including the pattern of reversal of taxable temporary differences and our future income from operations. Estimating future taxable income requires numerous judgments and assumptions, including projections of future operating conditions which may be impacted by volatile future prices for our oil, natural gas and natural gas production, the expected timing and quantity of future production volumes, and the impact of our commodity derivative instruments on our income.

In 2025, 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, supported the conclusion that Viper's deferred tax assets are more likely than not to be realized. The positive evidence assessed included recent cumulative income due in part to commodity prices remaining at a profitable level, acquisitions of additional oil and gas properties, and an expectation of future taxable income based upon recent actual and forecasted production volumes and prices. As of December 31, 2025, Viper had a net deferred tax asset of $33 million. Any changes in the positive or negative evidence evaluated when determining if Viper's deferred tax assets will be realized, including projected future income, could result in a material change to our consolidated financial statements. As of December 31, 2025, our balance of taxable temporary differences anticipated to reverse within the carryforward period provides significant positive evidence for the determination that our remaining deferred tax assets are more likely than not to be realized.

The accruals for deferred tax assets and liabilities are often based on unclear tax positions and 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. At December 31, 2025, we had no uncertain tax positions; however, 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.

Recent Accounting Pronouncements

See Note 2—Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data of this report for recent accounting pronouncements not yet adopted, if any.

Off-Balance Sheet Arrangements

See Note 15—Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data of this report for a discussion of our significant commitments and contingencies, some of which are not recognized in the consolidated balance sheets under GAAP.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

Our major market risk exposure 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. Both crude oil and natural gas realized prices are also impacted by the quality of the product, supply and demand balances in local physical markets and the availability of transportation to demand centers. Pricing for oil and natural gas production can be volatile and unpredictable. We cannot predict events that may lead to future price volatility and the near-term energy outlook remains subject to heightened levels of uncertainty as discussed in Item 1A. Risk Factors.

We use derivatives, including swaps, basis swaps, roll swaps, costless collars, puts and basis puts, to reduce price volatility associated with certain of our oil and natural gas sales. At December 31, 2025, we had a net asset derivative position of $198 million related to our commodity price risk derivatives. Utilizing actual derivative contractual volumes under our commodity price derivatives as of December 31, 2025, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position by $3 million to $195 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset position by $60 million to $258 million. However, any cash derivative gain or loss may be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

For additional information on our open commodity derivative instruments at December 31, 2025, see Note 12—Derivatives in Item 8. Financial Statements and Supplementary Data of this report.

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 $1.1 billion at December 31, 2025), and to a lesser extent, receivables resulting from joint interest and other receivables (approximately $258 million at December 31, 2025). Joint interest receivables arise from billings to entities that own partial interests in 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. We do not require our customers to post collateral and the failure or 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.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facilities, 2025 Term Loan, the Viper 2025 Term Loan and changes in the fair value of our fixed rate debt.

Outstanding borrowings under the Credit Agreement (as defined and discussed in Note 8—Debt in Item 8. Financial Statements and Supplementary Data of this report), which was undrawn at December 31, 2025, bear interest at a per annum rate elected by Diamondback E&P that is equal to (i) term SOFR or (ii) an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 1-month term SOFR plus 1.0%, subject to a 1.0% floor), in each case plus the applicable margin. At December 31, 2025, the applicable margin ranges from 0.000% to 0.750% per annum in the case of the alternate base rate and from 1.000% to 1.750% per annum in the case of term SOFR, in each case based on the pricing level for our revolving credit facility. We are obligated to pay a quarterly commitment fee ranging from 0.100% to 0.250% per year on the unused portion of the commitment for our revolving credit facility.

At December 31, 2025, outstanding borrowings of $550 million under the 2025 Term Loan bear interest at a per annum rate elected by the Company that is equal to (i) term SOFR plus 0.10% (“Adjusted Term SOFR”) or (ii) an alternate base rate (which is equal to the greatest of (a) the Federal Funds effective rate plus 0.50%, (b) the prime rate, (c) Adjusted Term SOFR plus 1.0%, and (d) 1.0%), in each case plus the applicable margin. The applicable margin ranges from 0.125% to 1.000% per annum in the case of the alternate base rate and from 1.125% to 2.000% per annum in the case of Adjusted Term SOFR, in each case based on the pricing level for the 2025 Term Loan. We are also obligated to pay a commitment fee equal to 0.125% per year on the aggregate principal amount of the commitments for the 2025 Term Loan. During the year ended December 31, 2025, the weighted average interest rate on borrowings under the 2025 Term Loan was 5.64%.

At December 31, 2025, outstanding borrowings of $105 million under the Viper Revolving Credit Facility bear interest at a floating rate equal to term SOFR or an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 1-month term SOFR plus 1.0%, subject to a 1.0% floor), in each case plus the applicable margin. The applicable margin ranges from 0.125% to 1.000% per annum in the case of the alternate base rate loans and from 1.125% to 2.000% per annum in the case of term SOFR loans, in each case based on the pricing level. Further, the commitment fee ranges from 0.125% to 0.325% per annum on the average daily unused portion of the commitment, based on the pricing level. The pricing level depends on the rating of Viper’s long-term senior unsecured debt by certain rating agencies. During the year ended December 31, 2025, the weighted average interest rate on borrowings under the Viper Revolving Credit Facility was 6.02%.

At December 31, 2025, outstanding borrowings of $500 million under the Viper 2025 Term Loan bear interest at a per annum rate elected by Viper that is equal to SOFR or an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 1-month term SOFR plus 1.0%, subject to a 1.0% floor), in each case plus the applicable margin. The applicable margin ranges from 0.250% to 1.125% per annum in the case of the alternate base rate loans and from 1.250% to 2.125% per annum in the case of term SOFR loans, in each case based on the pricing level. The pricing level depends on the rating of Viper’s long-term senior unsecured debt by certain ratings agencies. In addition, the fee on undrawn commitments is equal to 0.20% per annum on the aggregate principal amount of such commitments. During the year ended December 31, 2025, the weighted average interest rate on borrowings under the Viper 2025 Term Loan was 5.72%.

Historically, we have at times used interest rate swaps to manage our exposure to (i) interest rate changes on our floating-rate debt, and (ii) fair value changes on our fixed rate debt. At December 31, 2025, we have interest rate swap agreements for an aggregate $300 million notional amount to manage the impact of changes to the fair value of our fixed rate senior notes due to changes in market interest rates through December 2029. We pay an average variable rate of interest for these swaps based on 3-month SOFR plus 2.1865% and receive a fixed interest rate of 3.50% from our counterparties. At December 31, 2025, our receive-fixed, pay-variable interest rate swaps were in a liability position of $27 million, and the weighted average variable rate was 5.79%. For additional information on our interest rate swaps, see Note 12—Derivatives in Item 8. Financial Statements and Supplementary Data of this report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

(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.

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 (the “Company”) as of December 31, 2025 and 2024, the related consolidated statements of operations and comprehensive income, cash flows, and stockholders’ equity for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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, 2026 expressed an unqualified opinion.

Basis for opinion
These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated 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 and impairment expense, and the valuation of acquired reserves in connection with the Double Eagle Acquisition and the acquired mineral and royalty interests in the Sitio Acquisition

As described further in Note 2 to the consolidated financial statements, the Company accounts for its oil and natural 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 and impairment expense. Additionally, as described further in Note 4 to the consolidated financial statements, the Company acquired significant oil and natural gas properties and mineral and royalty interests through the Double Eagle Acquisition and Sitio Acquisition, respectively, which requires management to make estimates of reserve volumes and future revenues to value the properties. To estimate the volume of reserves and future revenues, management makes significant estimates and assumptions, including forecasting the timing and volumetric amounts of production and corresponding decline rate of producing properties associated with the Company’s development plan. In addition, the estimation of reserves is impacted by management’s judgments and estimates regarding the financial performance of wells to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions. For acquired reserves, management utilizes an estimated fair value pricing model in determining the corresponding value of reserves. We identified the estimation of reserves attributable to oil and natural gas properties, including acquired reserves in the Double Eagle Acquisition and Sitio Acquisition, due to its impact on depletion and impairment expense and acquisition accounting, as a critical audit matter.

The principal consideration for our determination that the estimation of reserves is a critical audit matter is that changes in certain inputs and assumptions, which include a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company's reserves, could have a significant impact on the measurement of depletion and impairment expense and the fair value of acquired oil and natural gas properties and mineral and royalty interests. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the design and operating effectiveness of key controls relating to management's estimation of reserves for the purpose of calculating depletion and impairment expense and management's estimation of the fair value of the acquired oil and natural gas properties in the Double Eagle Acquisition and Sitio Acquisition.

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

- Identified inputs and assumptions that were significant to the period end determination of proved reserve volumes and tested management's process of determining the significant inputs and assumptions, as follows:

    - Compared the pricing used in the reserve report to relevant pricing benchmarks and realized prices related to revenue transactions recorded in the current year;

    - Assessed the reasonableness of forecasted capital expenditures by comparing drilling forecasts applied in the reserve report to recent drilling costs;

    - Vouched, on a sample basis, the working and net revenue interests used in the reserve report to underlying land and division order records;

    - Assessed forecasted production estimates by (i) comparing prior year forecasted production amounts to current year actual results and (ii) comparing forecasted production amounts in the current year reserve report to the actual historical production amounts in the current year, in total and for a sample of individual wells;

    - Obtained evidence supporting the development of proved undeveloped properties reflected in the reserve report and compared future development plans to historical conversion rates to evaluate the likelihood of development related to the proved undeveloped properties; and

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

- Identified inputs and assumptions that were significant to the estimated fair value of the acquired oil and natural gas properties in the Double Eagle Acquisition and Sitio Acquisition, respectively, and tested management's process of determining the significant inputs and assumptions, as follows:

    - Evaluated the appropriateness of fair value pricing, including pricing differentials, used in the fair value reserve reports by comparing the pricing forecast to published product pricing as of the acquisition closing dates and pricing differentials to actual historical realized pricing of the acquired properties;

    - Evaluated the level of knowledge, skill and ability of the specialists utilized by the Company to assist in the preparation of the estimates of fair value of oil and natural gas properties and mineral and royalty interests acquired;

    - Utilized a valuation specialist to evaluate the reasonableness of the Company's valuation methodology of the Double Eagle Acquisition and Sitio Acquisition, respectively, including testing key inputs and assumptions by understanding and assessing the process used to develop the estimate or through development of an independent expectation;

- Evaluated the appropriateness of the future operating cost and capital expenditure assumptions used in the Double Eagle Acquisition fair value reserve report by comparing forecasted amounts to historical operating costs and to recent drilling costs;

- Compared, on a sample basis, the working interest, as applicable, and net revenue interests used in the fair value reserve reports to historical reserve reports;

- Assessed forecasted production estimates in the fair value reserve reports for reasonableness by comparing forecasted production amounts to the actual historical production amounts and to the forecasted production in the year-end reserve report for a sample of individual wells;

- Applied analytical procedures on the fair value reserve reports' forecasted production by comparing to the prior year reserve reports' forecasted production and to the year-end reserve reports' forecasted production of the acquired proved properties; and

- Compared the unproved acreage value allocated to other recent acquisitions in the same or similar locations.

/s/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma
February 25, 2026

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations and Comprehensive Income

	Year Ended December 31,		
	2025	2024	2023
	(In millions, except per share amounts, shares in thousands)		
Revenues:			
Oil sales	$ 11,621	$ 9,067	$ 7,279
Natural gas sales	400	89	262
Natural gas liquid sales	1,432	944	687
Sales of purchased oil	1,476	923	111
Other operating income	97	43	73
Total revenues	15,026	11,066	8,412
Costs and expenses:			
Lease operating expenses	1,865	1,286	872
Production and ad valorem taxes	851	638	525
Gathering, processing and transportation	515	356	287
Purchased oil expense	1,474	921	111
Depreciation, depletion, amortization and accretion	5,038	2,850	1,746
Impairment of oil and natural gas properties	3,652	—	—
General and administrative expenses	288	213	150
Other operating expenses, net	77	406	151
Total costs and expenses	13,760	6,670	3,842
Income (loss) from operations	1,266	4,396	4,570
Other income (expense):			
Interest expense, net	(244)	(135)	(159)
Other income (expense), net	455	101	100
Gain (loss) on derivative instruments, net	341	137	(259)
Gain (loss) on extinguishment of debt, net	56	2	(4)
Total other income (expense), net	608	105	(322)
Income (loss) before income taxes	1,874	4,501	4,248
Provision for (benefit from) income taxes	327	800	912
Net income (loss)	1,547	3,701	3,336
Net income (loss) attributable to non-controlling interest	(117)	363	193
Net income (loss) attributable to Diamondback Energy, Inc.	$ 1,664	$ 3,338	$ 3,143
Earnings (loss) per common share:			
Basic	$ 5.73	$ 15.53	$ 17.34
Diluted	$ 5.73	$ 15.53	$ 17.34
Weighted average common shares outstanding:			
Basic	289,079	213,545	179,999
Diluted	289,079	213,545	179,999
Comprehensive income (loss):			
Net income (loss) attributable to Diamondback Energy, Inc.	$ 1,664	$ 3,338	$ 3,143
Other comprehensive income (loss), net of tax:			
Pension and postretirement benefit plans	(1)	2	(1)
Comprehensive income (loss) attributable to Diamondback Energy, Inc	$ 1,663	$ 3,340	$ 3,142

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2025	December 31, 2024
	(In millions, except par value and share amounts)	
Assets		
Current assets:		
Cash and cash equivalents ($13 million and $27 million related to Viper)	$ 104	$ 161
Restricted cash	2	3
Accounts receivable:		
Joint interest and other, net	258	198
Oil and natural gas sales, net ($262 million and $149 million related to Viper)	1,128	1,387
Inventories	86	116
Prepaid expenses and other current assets ($50 million and $31 million related to Viper)	337	245
Total current assets	1,915	2,110
Property and equipment:		
Oil and natural gas properties:		
Proved properties ($9,746 million and $3,533 million related to Viper)	71,588	59,574
Unproved properties ($4,910 million and $2,180 million related to Viper)	23,941	22,666
Other property, equipment and land	874	1,440
Accumulated depletion, depreciation, amortization and impairment ($2,455 million and $1,081 million related to Viper)	(27,782)	(19,208)
Property and equipment, net	68,621	64,472
Other assets	523	710
Total assets	$ 71,059	$ 67,292
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued capital expenditures	$ 1,168	$ 943
Current maturities of debt	763	900
Other accrued liabilities	1,108	1,020
Revenues and royalties payable	1,397	1,491
Derivative instruments	15	43
Income taxes payable	149	414
Total current liabilities	4,600	4,811
Long-term debt ($2,186 million and $1,083 million related to Viper)	13,726	12,075
Deferred income taxes	9,141	9,826
Other long-term liabilities	625	718
Total liabilities	28,092	27,430
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Common stock, $0.01 par value; 800,000,000 shares authorized; 284,594,908 and 290,984,373 shares issued and outstanding at December 31, 2025 and December 31, 2024, respectively	3	3
Additional paid-in capital	32,236	33,501
Retained earnings (accumulated deficit)	4,740	4,238
Accumulated other comprehensive income (loss)	(7)	(6)
Total Diamondback Energy, Inc. stockholders' equity	36,972	37,736
Non-controlling interest	5,995	2,126
Total equity	42,967	39,862
Total liabilities and stockholders' equity	$ 71,059	$ 67,292

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Cash flows from operating activities:			
Net income (loss)	$ 1,547	$ 3,701	$ 3,336
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Provision for (benefit from) deferred income taxes	(519)	15	378
Depreciation, depletion, amortization and accretion	5,038	2,850	1,746
Impairment of oil and natural gas properties	3,652	—	—
(Gain) loss on extinguishment of debt	(56)	(2)	4
(Gain) loss on derivative instruments, net	(341)	(137)	259
Cash received (paid) on settlement of derivative instruments	181	(51)	(110)
Other	(430)	133	11
Changes in operating assets and liabilities:			
Accounts receivable	386	(42)	(71)
Accounts payable and accrued liabilities	(343)	(376)	57
Income taxes payable	(399)	87	(5)
Revenues and royalties payable	15	168	123
Other	27	67	192
Net cash provided by (used in) operating activities	8,758	6,413	5,920
Cash flows from investing activities:			
Additions to oil and natural gas properties	(3,523)	(2,867)	(2,701)
Property acquisitions	(5,938)	(8,920)	(2,013)
Proceeds from sale of assets	1,670	467	1,407
Other	(18)	99	(16)
Net cash provided by (used in) investing activities	(7,809)	(11,221)	(3,323)
Cash flows from financing activities:			
Proceeds from debt	15,042	9,875	5,179
Repayment of debt	(13,467)	(3,502)	(4,802)
Repurchased shares under repurchase program	(1,705)	(959)	(840)
Repurchased shares - related party	(305)	—	—
Proceeds from partial sale of investment in Viper	—	451	—
Net proceeds from Viper’s issuance of common stock	1,232	476	—
Dividends paid to stockholders	(1,156)	(1,578)	(1,444)
Dividends/distributions to non-controlling interest	(382)	(227)	(129)
Other	(266)	(149)	(140)
Net cash provided by (used in) financing activities	(1,007)	4,387	(2,176)
Net increase (decrease) in cash, cash equivalents and restricted cash	(58)	(421)	421
Cash, cash equivalents and restricted cash at beginning of period	164	585	164
Cash, cash equivalents and restricted cash at end of period	$ 106	$ 164	$ 585

See accompanying notes to consolidated financial statements.

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	Shares	Amount					
	($ in millions, shares in thousands)						
Balance at December 31, 2022	179,841	$ 2	$ 14,213	$ 801	$ (7)	$ 681	$ 15,690
Viper common stock issued for acquisition	—	—	—	—	—	255	255
Viper stock-based compensation	—	—	—	—	—	1	1
Distribution equivalent rights payments	—	—	—	(11)	—	—	(11)
Stock-based compensation	394	—	79	—	—	—	79
Cash paid for tax withholding on vested equity awards	(146)	—	(20)	—	—	—	(20)
Repurchased shares under repurchase program, including excise tax	(6,238)	—	(840)	—	—	—	(840)
Repurchased shares/units under Viper's repurchase programs	—	—	—	—	—	(95)	(95)
Common stock issued for acquisition	4,330	—	633	—	—	—	633
Dividends/distributions to non-controlling interest	—	—	—	—	—	(129)	(129)
Dividend paid	—	—	—	(1,444)	—	—	(1,444)
Exercise of stock options and issuance of restricted stock units and awards	543	—	—	—	—	—	—
Change in ownership of consolidated subsidiaries, net	—	—	77	—	—	(101)	(24)
Other comprehensive income (loss), net of tax	—	—	—	—	(1)	—	(1)
Net income (loss)	—	—	—	3,143	—	193	3,336
Balance at December 31, 2023	178,724	2	14,142	2,489	(8)	805	17,430
Viper stock-based compensation	—	—	—	—	—	4	4
Distribution equivalent rights payments	—	—	—	(11)	—	—	(11)
Stock-based compensation	—	—	91	—	—	—	91
Cash paid for tax withholding on vested equity awards	(203)	—	(39)	—	—	—	(39)
Repurchased shares under repurchase program, including excise tax	(5,526)	—	(959)	—	—	—	(959)
Common shares issued for acquisition	117,267	1	20,109	—	—	—	20,110
Viper LLC's units issued for acquisition	—	—	—	—	—	468	468
Proceeds from partial sale of investment in Viper	—	—	219	—	—	197	416
Net proceeds from Viper's issuance of common stock	—	—	—	—	—	476	476
Dividends to non-controlling interest	—	—	—	—	—	(227)	(227)
Dividends paid	—	—	—	(1,578)	—	—	(1,578)
Issuance of shares upon vesting of equity awards	722	—	—	—	—	—	—
Change in ownership of consolidated subsidiaries, net	—	—	(62)	—	—	40	(22)
Other comprehensive income (loss), net of tax	—	—	—	—	2	—	2
Net income (loss)	—	—	—	3,338	—	363	3,701
Balance at December 31, 2024	290,984	3	33,501	4,238	(6)	2,126	39,862
Viper stock-based compensation	—	—	—	—	—	7	7
Stock-based compensation	—	—	107	—	—	—	107
Cash paid for tax withholding on vested equity awards	(163)	—	(26)	—	—	—	(26)
Issuance of shares upon vesting of equity awards	664	—	—	—	—	—	—
Repurchased shares under repurchase program, including excise tax	(11,838)	—	(1,711)	—	—	—	(1,711)
Repurchased shares - related party, including excise tax	(2,000)	—	(308)	—	—	—	(308)
Repurchased shares under Viper's repurchase program	—	—	—	—	—	(194)	(194)
Dividends to non-controlling interest	—	—	—	—	—	(382)	(382)
Dividends paid	—	—	—	(1,156)	—	—	(1,156)
Distribution equivalent rights payments	—	—	—	(6)	—	(1)	(7)
Common shares issued for acquisition	6,948	—	1,116	—	—	—	1,116
Viper common stock issued for acquisition	—	—	—	—	—	1,435	1,435
Viper LLC's units issued for acquisition	—	—	—	—	—	1,445	1,445
Net proceeds from Viper's issuance of common stock	—	—	—	—	—	1,232	1,232
Change in ownership of consolidated subsidiaries, net	—	—	(444)	—	—	444	—
Other comprehensive income (loss), net of tax	—	—	1	—	(1)	—	—
Net income (loss)	—	—	—	1,664	—	(117)	1,547
Balance at December 31, 2025	284,595	$ 3	$ 32,236	$ 4,740	$ (7)	$ 5,995	$ 42,967

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., together with its subsidiaries (collectively referred to as “Diamondback,” the “Company,” “we” or “our” unless the context otherwise requires), is an independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas.

As of December 31, 2025, the wholly owned subsidiaries of Diamondback include Diamondback E&P LLC, a Delaware limited liability company, Rattler Midstream GP LLC, a Delaware limited liability company, Rattler Midstream LP, a Delaware limited partnership, QEP Resources, Inc. (“QEP”), a Delaware corporation, Diamondback RE Holdco LLC, a Delaware limited liability company and Eclipse Merger Sub II, LLC, a Delaware limited liability company.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries, including its publicly-traded subsidiary, Viper Energy, Inc., after all significant intercompany balances and transactions have been eliminated upon consolidation. As of December 31, 2025, the Company is managed as one operating and reportable segment, 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 includes the activities of Viper as well as the Company’s remaining midstream operations.

On August 19, 2025, upon completion of Viper’s Sitio Acquisition (as defined and discussed in Note 4—Acquisitions and Divestitures), VNOM Sub, Inc., (formerly Viper Energy, Inc., “Former Viper”) became a wholly owned subsidiary of Viper Energy Inc., (formerly New Cobra Pubco, Inc., “New Viper”).

As of December 31, 2025, the Company owned approximately 42% of Viper’s combined outstanding Class A common stock and Class B common stock on a fully diluted basis, after giving effect to the outstanding TWR Class B Option (as defined and discussed in Note 4—Acquisitions and Divestitures). The Company determined that it controls the activities of Viper in accordance with the guidance for variable interest entities in Accounting Standards Codification (“ASC”) Topic 810, “Consolidation,” and therefore continues to consolidate Viper in the Company’s financial statements at December 31, 2025. See further discussion of the Company’s determination that Viper is a variable interest entity (“VIE”) in Note 2—Summary of Significant Accounting Policies. The results of operations attributable to the non-controlling interest in Viper are presented within equity and net income and are shown separately from the equity and net income attributable to the Company.

On November 13, 2023, the Company’s publicly traded subsidiary, Viper Energy Partners LP, completed its conversion from a Delaware limited partnership into a Delaware corporation, Viper Energy, Inc. (the “Viper Conversion”). At the time of the Viper Conversion, Viper was a “controlled company” under the Nasdaq rules because the Company owned more than 50% of the voting power of Viper’s common stock. On October 31, 2023, pursuant to a common unit purchase and sale agreement entered into on September 4, 2023, Viper issued approximately 7.22 million of its common units, which were converted to shares of Viper Class A common stock at the time of the Viper Conversion, to the Company at a price of $27.72 per unit for total consideration to Viper of approximately $200 million. On March 5, 2024, the Company exercised certain of its demand rights, pursuant to a registration rights agreement amended and restated on November 10, 2023, and on March 8, 2024, completed a public offering of approximately 13.23 million shares of Viper’s Class A common stock at a price of $35.00 per share for proceeds, net of underwriters’ discount, of approximately $451 million. After this offering, the Company owned less than 50% of Viper’s combined outstanding Class A common stock and Class B common stock, resulting in Viper no longer being a controlled company under the Nasdaq rules. References to “Viper” refer to (i) New Viper following the Sitio Acquisition, (ii) Former Viper prior to the Sitio Acquisition but after the Viper Conversion, and (iii) Viper Energy Partners LP prior to the Viper Conversion. For definition and details on Viper’s Sitio Acquisition, see Note 4—Acquisitions and Divestitures.

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 liabilities as of the date of the consolidated financial statements. Actual results could differ from those estimates.

Making accurate estimates and assumptions is particularly difficult in the oil and natural gas industry given the challenges resulting from volatility in oil and natural gas prices. For instance, geopolitical conflicts, higher interest rates, effects of tariffs, actions taken by OPEC and its non-OPEC allies, global supply chain disruptions, measures to combat persistent inflation and instability in the financial sector have contributed to recent economic and pricing volatility. The financial results of companies in the oil and natural gas industry have been and may continue to be impacted materially as a result of these events and changing market conditions. Such circumstances generally increase 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, the fair value determination of assets acquired and liabilities assumed and estimates of income taxes, including deferred tax valuation allowances.

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 to account for various factors depending on the points of sale. As a result, the prices of the Company's oil, natural gas and natural gas liquids fluctuate to remain competitive with other available 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. 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. Generally, 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. Under contracts where the Company has concluded that it is the agent, the Company recognizes revenue on a net basis, with transportation, gathering, processing, treating and compression fees as a reduction to revenues in the 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 gathering, processing and transportation expense in the consolidated statements of operations.

Sales of Purchased Oil and Purchased Oil Expense

The Company enters into capacity commitments in order to secure available transportation capacity from the Company's areas of production for its commodities. Beginning in the third quarter of 2023, the Company also entered into purchase transactions with third parties and separate sale transactions with third parties to satisfy certain of its unused capacity commitments. Revenues and expenses from these transactions are generally presented on a gross basis in the captions "Sales of purchased oil" and "Purchased oil expense" in the accompanying consolidated statements of operations as the Company acts as a principal in the transaction by assuming both the risks and rewards of ownership, including credit risk, of the oil volumes purchased and the responsibility to deliver the oil volumes sold.

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 day's production. Therefore, there are no remaining performance obligations under any of its product sales contracts.

Under the Company's 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, 2025, 2024 and 2023 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.

See Note 3—Revenue from Contracts with Customers for additional discussion of the Company's revenues.

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 and natural gas liquids 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 internal 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. Divestitures 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 and natural liquids. 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 $14.60, $12.60 and $10.21 for the years ended December 31, 2025, 2024 and 2023, respectively. Depletion expense for oil and natural gas properties was $4.9 billion, $2.8 billion and $1.7 billion for the years ended December 31, 2025, 2024 and 2023, respectively.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized oil and natural gas properties 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 on proved oil and natural gas properties and related ceiling test impairments, see Note 5—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 a group basis, as a majority of 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.

Accounting for Equity-Based Compensation

The Company has granted various types of stock-based awards primarily including restricted stock units and performance based restricted stock units. Viper has also granted various stock-based awards including restricted stock units and performance based restricted stock units to its directors and to Diamondback employees and officers who perform services for Viper. These plans and related accounting policies for material awards are defined and described more fully in Note 10—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.

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. For commodity derivative instruments and interest rate swaps which have not been designated as hedges for accounting purposes, the Company 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. To the extent that contracts with the same counterparty are allowed to be netted upon payment subject to a master netting arrangement, these amounts are reported on a net basis on the consolidated balance sheets. The Company previously had certain interest rate swaps designated as fair value hedges under the “shortcut” method of accounting. In the second quarter of 2022, the Company elected to fully dedesignate these interest rate swaps and hedge accounting was discontinued. The remaining unamortized basis adjustment related to the dedesignated interest rate swaps is reflected as a reduction to long-term debt on the consolidated balance sheet as detailed in Note 8—Debt. For additional information regarding the Company’s derivative instruments, see Note 12—Derivatives.

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.

The Company records uncertain tax positions based on a two-step process: (i) determine whether it is more likely than not that the tax positions will be sustained on the basis of the technical merits of the position, and (ii) for those tax positions that meet the more-likely-than-not recognition threshold, recognize the largest amount of tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. For additional information regarding income taxes, see Note 11—Income Taxes.

Non-Controlling Interests

Non-controlling interests in the accompanying consolidated financial statements represent the public’s ownership interest in Viper and are presented as a component of equity. When the Company’s relative ownership interests change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, occur. Because these changes in the ownership interests 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 the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. See Note 9—Stockholders’ Equity and Earnings (Loss) Per Share for a discussion of changes in the Company’s ownership interest in consolidated subsidiaries during the years ended December 31, 2025, 2024 and 2023.

Cash, Cash Equivalents and Restricted Cash

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.

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 utilizing the loss-rate method, which considers 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, 2025 and 2024, the Company’s allowances for credit losses related to joint interest receivables and credit losses related to sales of oil and natural gas production were not material.

Inventories

Inventories are stated at the lower of cost or net realizable value and primarily consist of tubular goods and equipment at December 31, 2025 and 2024. 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.

Prepaid Expenses and Other Current Assets

The following table shows the components of prepaid expenses and other current assets for the periods indicated:

	December 31,	
	2025	2024
	(In millions)	
Derivative instruments	$ 234	$ 168
Prepaid expenses	96	74
Other	7	3
Prepaid expenses and other current assets	$ 337	$ 245

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 the statement of operations. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from three years to 30 years.

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 impairment losses for the years ended December 31, 2025, 2024 and 2023.

Equity Method Investments

The Company accounts for its corporate joint ventures and equity investments under the equity method of accounting in accordance with ASC Topic 323 “Investments — Equity Method and Joint Ventures.” The Company applies the equity method of accounting to investments of less than 50% in an investee over which the Company has the ability to exercise significant influence but does not have control, and investments of greater than 50% in an investee over which the Company does not exercise significant influence or have control. Under the equity method of accounting, the Company’s share of the investee’s earnings or loss is recognized in the statement of operations. As of December 31, 2025, the Company’s proportionate share of the income or loss from equity method investments is recognized on a two-month lag for its significant equity method investments.

Judgment regarding the level of influence over each equity method investment includes considering key factors such as, but not limited to, 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 non-controlling investment shall be accounted for using the equity method or as an investment over which we do not have the ability to exercise significant influence.

The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such a loss has occurred, the Company recognizes an impairment provision. There were no significant impairments of the Company's equity investments for the years ended December 31, 2025, 2024 and 2023.

Other Accrued Liabilities

The Company's accrued liabilities are financial instruments for which the carrying value approximates fair value.

Other accrued liabilities consist of the following at December 31, 2025 and 2024:

	December 31,	
	2025	2024
	(In millions)	
Lease operating expenses payable	$ 390	$ 354
Ad valorem taxes payable	240	242
Accrued compensation	96	79
Interest payable	187	145
Derivative liability payable	16	16
Other	179	184
Total other accrued liabilities	$ 1,108	$ 1,020

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.

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 8—Debt for further details.

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 8—Debt for further details. The costs associated with the Company's credit facilities and term loans are included in other assets on the consolidated balance sheet and are amortized over the term of the facility.

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 6—Asset Retirement Obligations.

Variable Interest Entity

Viper is a publicly traded corporation formed by the Company in 2014 to provide an attractive return to its stockholders (the largest of which is Diamondback) by focusing on business results, maximizing dividends through organic growth and pursuing accretive growth opportunities through acquisitions of mineral, royalty, overriding royalty, net profits and similar interests from the Company and from third parties. Viper has no employees and the Company provides management, operating and administrative services to Viper under a services and secondment agreement, including the services of the executive officers and other employees.

In connection with the reduction of the Company's ownership percentage in Viper to below 50% in March 2024, the Company re-evaluated whether Viper should continue to be consolidated in the Company's financial statements. Viper meets the definition of a VIE under ASC Topic 810, "Consolidation," and the Company continues to be the primary beneficiary of the VIE through its ability, via existing contractual agreements, to direct the activities that most significantly affect Viper's economic performance. The Company also has the obligation to absorb losses and the right to receive benefits that could be significant to Viper. As such, the Company continues to consolidate the activity of Viper. The Viper 2024 Equity Offering, the Viper 2025 Equity Offering (each as defined and discussed in Note 9—Stockholders' Equity and Earnings (Loss) Per Share), the 2025 Drop Down and Viper's Sitio Acquisition (each as defined and discussed in Note 4—Acquisitions and Divestitures) were evaluated and determined not to be events that would cause the Company to change its conclusion regarding Viper's status as a VIE, and the Company continues to be the primary beneficiary.

Viper maintains its own capital structure that is separate from the Company, and the Company is not under any obligation to provide additional financial support or investment to Viper. Viper's assets cannot be used by the Company for general corporate purposes, and the creditors of Viper's liabilities do not have recourse to the Company's assets. The assets and liabilities of Viper are included in the Company's consolidated balance sheets and disclosed parenthetically, if material.

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.

Recent Accounting Pronouncements

Recently Adopted Pronouncements

In December 2023, the FASB issued ASU 2023-09, "Income Taxes (Topic 740) – Improvements to Income Tax Disclosures," which requires that certain information in a reporting entity's tax rate reconciliation be disaggregated and provides additional requirements regarding income taxes paid. The Company adopted the amendments in 2025 and applied the guidance on a retrospective basis. Adoption of the update resulted in additional disclosures in Note 11—Income Taxes but did not impact the Company's financial position, results of operations or liquidity.

In September 2025, the FASB issued ASU 2025-07, "Derivatives and Hedging (Topic 815) and Revenue from Contracts with Customers (Topic 606) – Derivatives Scope Refinements and Scope Clarification for Share-Based Noncash Consideration from a Customer in a Revenue Contract." The ASU addresses (i) the application of derivative accounting to contracts that include features based on the operations or activities of one of the parties to the contract, and (ii) diversity in practice related to accounting for share-based noncash consideration from a customer. The Company elected to early-adopt this amendment in 2025 and applied the guidance on a prospective basis. Adoption of the update did not impact the

Company’s historical financial position, results of operations or liquidity; however, the guidance may affect whether certain new arrangements qualify for derivative accounting.

Accounting Pronouncements Not Yet Adopted

In November 2024, the FASB issued ASU 2024-03, “Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40) – Disaggregation of Income Statement Expenses,” which requires additional disclosure about specified categories of expenses included in relevant expense captions presented on the income statement. The amendments are effective for annual periods beginning after December 15, 2026, and for interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. The amendments may be applied either prospectively or retrospectively. Management is currently evaluating this ASU to determine its impact on the Company’s disclosures. Adoption of the update will not impact the Company’s 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, previously disclosed, or not material upon adoption.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue from Contracts with Customers

The following tables present the Company’s revenue from contracts with customers:

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Oil sales	$ 11,621	$ 9,067	$ 7,279
Natural gas sales	400	89	262
Natural gas liquid sales	1,432	944	687
Total oil, natural gas and natural gas liquid revenues	13,453	10,100	8,228
Sales of purchased oil	1,476	923	111
Other service revenues	65	29	62
Total revenue from contracts with customers	$ 14,994	$ 11,052	$ 8,401

The following tables present the Company’s revenue from oil, natural gas and natural gas liquids disaggregated by basin:

	Year Ended December 31, 2025			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 10,729	$ 850	$ 42	$ 11,621
Natural gas sales	349	45	6	400
Natural gas liquid sales	1,321	111	—	1,432
Total	$ 12,399	$ 1,006	$ 48	$ 13,453

	Year Ended December 31, 2024			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 7,711	$ 1,347	$ 9	$ 9,067
Natural gas sales	65	23	1	89
Natural gas liquid sales	779	165	—	944
Total	$ 8,555	$ 1,535	$ 10	$ 10,100

	Year Ended December 31, 2023			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 5,746	$ 1,527	$ 6	$ 7,279
Natural gas sales	176	85	1	262
Natural gas liquid sales	500	187	—	687
Total	$ 6,422	$ 1,799	$ 7	$ 8,228

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, 2025, four purchasers each accounted for more than 10% of our revenue: Medallion Midstream (16%), Shell Trading (USA) Company (“Shell”) (13%), Enterprise Crude Oil LLC (“Enterprise”) (12%) and Vitol Inc. (“Vitol”) (11%). For the year ended December 31, 2024, four purchasers each accounted for more than 10% of the Company’s revenue: Vitol (17%), Enterprise (15%), Shell (13%) and DK Trading & Supply LLC (“DK”) (11%). For the year ended December 31, 2023, four purchasers each accounted for more than 10% of the Company’s revenue: Vitol (22%), DK (18%), Shell (14%) and Enterprise (13%). 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

2025 Activity

Diamondback Acquisitions and Divestitures

EPIC Divestiture

On October 31, 2025, the Company divested its 27.5% equity interest in EPIC Crude Holdings, LP (“EPIC”) pursuant to a definitive purchase and sale agreement with Plains All American Pipeline, L.P. and Plains GP Holdings for approximately $504 million in cash and an additional $96 million in unrecognized contingent consideration (the “EPIC Divestiture”). The EPIC Divestiture resulted in a gain on the sale of equity method investments of approximately $299 million, which is included in the caption “Other income (expense), net” on the consolidated statements of operations for the year ended December 31, 2025. The contingent cash payment is due should the capacity expansion of EPIC be formally sanctioned before year-end 2027.

Divestiture of Water Assets to Deep Blue

On October 1, 2025, the Company divested Environmental Disposal Systems, LLC, a subsidiary originally acquired in connection with the Endeavor Acquisition, to Deep Blue Midland Basin LLC (“Deep Blue”), in exchange for upfront net cash proceeds of $694 million, subject to customary post-closing adjustments, and approximately $34 million of additional equity interests issued by Deep Blue as non-cash consideration. The transaction provides for the potential for the Company to earn up to an additional $200 million. If certain completion thresholds are not met, the Company could owe up to $150 million in contingent consideration for the years 2026 through 2028. The Company will recognize any contingent gains when realizable at the end of each annual measurement period, or will accrue a contingent loss if at any time a payable to Deep Blue becomes probable and reasonably estimable. The divestiture resulted in a gain of approximately $168 million, which is included in the caption "Other operating expenses, net" on the consolidated statements of operations for the year ended December 31, 2025. As part of the divestiture, the Company renewed its 15-year dedication to Deep Blue for its produced water and supply water within a 12-county area of mutual interest in the Midland Basin. The Company's equity ownership interest in Deep Blue remained at 30% following the closing of the transaction. The cash proceeds from the divestiture were used to repay borrowings under the Credit Agreement (as defined and discussed in Note 8—Debt) and for general corporate purposes.

2025 Drop Down

On May 1, 2025, the Company's wholly owned subsidiary Endeavor Energy Resources, LP ("EER LP") divested all of the issued and outstanding equity interests in 1979 Royalties, LP and 1979 Royalties GP, LLC (collectively, the "Endeavor Subsidiaries"), each of which was a subsidiary of the Company, pursuant to a definitive equity purchase agreement with Viper and Viper LLC in exchange for consideration consisting of (i) $873 million in cash including customary post-closing adjustments, and (ii) the issuance of 69.63 million Viper LLC units and an equivalent number of shares of Viper's Class B common stock (the "2025 Drop Down"). The Company incurred $21 million in advisory, legal and filing fees related to the 2025 Drop Down, which are reflected in the consolidated statement of operations in the caption "Other operating expenses, net." Viper funded the cash consideration for the 2025 Drop Down with a portion of the proceeds from the Viper 2025 Equity Offering (as defined and discussed in Note 9—Stockholders' Equity and Earnings (Loss) Per Share) and borrowings under the Viper Revolving Credit Facility (as defined and discussed in Note 8—Debt). The 2025 Drop Down was accounted for as a transaction between entities under common control.

EER LP can exchange some or all of the Viper LLC units received together with an equal number of shares of Viper's Class B common stock for an equal number of shares of Viper's Class A common stock. The mineral and royalty interests held and divested by the Endeavor Subsidiaries at the closing of the 2025 Drop Down represented approximately 24,446 net royalty acres in the Permian Basin, 69% of which were operated by the Company, have an average net royalty interest of approximately 2.2% and had oil production as of the closing date of approximately 17,097 BO/d (the "Endeavor Mineral and Royalty Interests"). The Endeavor Mineral and Royalty Interests included interests in horizontal wells comprised of 5,574 gross proved developed production wells (of which approximately 32% were operated by the Company), 116 gross completed wells and 394 gross drilled but uncompleted wells, all of which were principally concentrated in the Midland Basin, with the balance located primarily in the Delaware and Williston Basins.

Double Eagle Acquisition

On April 1, 2025, the Company completed its acquisition of all of the issued and outstanding interests of DE Permian, LLC, DE IV Combo, LLC and DE IV Operating, LLC, each of which were wholly owned subsidiaries of Double Eagle IV Midco, LLC (the "Double Eagle Acquisition") for consideration of $3.1 billion in cash and approximately 6.84 million shares of the Company's common stock, including transaction costs and subject to certain customary post-closing adjustments. The assets acquired in the Double Eagle Acquisition consisted of approximately 67,700 gross (40,000 net) acres, which are primarily located in the Midland Basin and approximately 407 gross (342 net) horizontal locations in primary development targets. The Company funded the cash portion of the Double Eagle Acquisition through a combination of proceeds from the 2035 Notes (as defined and discussed in Note 8—Debt), proceeds from the 2025 Term Loan (as defined and discussed in Note 8—Debt) and borrowings under the Company's revolving credit facility. The Double Eagle Acquisition was accounted for as an asset acquisition in accordance with ASC Topic 805, "Business Combinations."

Other Transactions

During the year ended December 31, 2025, the Company completed individually insignificant acquisitions for an aggregate purchase price of approximately $879 million, including customary closing adjustments.

The Company divested non-core assets in individually insignificant transactions for an aggregate of approximately $464 million in proceeds, including customary closing adjustments, during the year ended December 31, 2025.

During the year ended December 31, 2025, the Company exchanged assets valued at approximately $835 million, including customary closing adjustments, in individually insignificant non-monetary transactions.

Viper Acquisition

Sitio Acquisition

On August 19, 2025, Viper completed a series of transactions in which New Viper acquired Sitio Royalties Corp. ("Sitio"), Sitio Royalties Operating Partnership, LP ("Sitio OpCo") and their respective subsidiaries, pursuant to the Agreement and Plan of Merger, dated June 2, 2025, by and among Former Viper, Viper LLC, Sitio, Sitio OpCo, New Viper, Cobra Merger Sub, Inc. and Scorpion Merger Sub, Inc. (the "Sitio Acquisition"). The Sitio Acquisition was an all-equity transaction valued at approximately $4.0 billion, including customary transaction costs and post-closing adjustments and the partial retirement of Sitio's net debt of approximately $1.2 billion.

The mineral and royalty interests acquired in the Sitio Acquisition represent approximately 25,300 net royalty acres in the Permian Basin and approximately 9,000 net royalty acres in the Denver-Julesburg, Eagle Ford and Williston basins, for total acreage of approximately 34,300 net royalty acres. See Note 16—Subsequent Events for discussion of divestiture of the Viper non-Permian acreage in 2026. The Sitio Acquisition was accounted for as an asset acquisition in accordance with ASC Topic 805, "Business Combinations."

2024 Activity

Diamondback Acquisitions and Divestiture

TRP Exchange

On December 20, 2024, the Company completed a transaction with TRP Energy, LLC ("TRP"), in which the Company exchanged certain assets including approximately 47,034 gross (35,673 net) acres located in the Delaware Basin and $312 million in cash, subject to customary post-closing adjustments, for certain of TRP's assets consisting of approximately 21,582 gross (15,421 net) acres located in the Midland Basin with 55 operated locations (the "TRP Exchange"). The TRP Exchange expanded our operating footprint and enhanced our inventory of near-term drilling locations, and was valued at approximately $1.3 billion. The Company funded the cash portion of the exchange with cash on hand and borrowings under its revolving credit facility.

The following table presents the acquisition consideration transferred in the TRP Exchange (in millions):

Consideration:		
Oil and natural gas properties	$	989
Midstream assets		53
Suspense liabilities relieved		(9)
Cash consideration		312
Total consideration	$	1,345

Acquisition Date Fair Value of Consideration Transferred

The acquisition date fair value of oil and natural gas properties transferred was determined using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. These inputs are not observable in the market and are considered level 3 inputs within the fair value hierarchy. The oil and natural gas properties transferred did not significantly impact the Company's capitalized costs or proved reserves as of December 31, 2024.

The acquisition date fair value of midstream assets transferred was determined based on the cost approach, which utilized asset listings and cost records with consideration for the age, condition, utilization and economic support of the assets.

Allocation of Consideration Transferred

The TRP Exchange has been accounted for under the acquisition method of accounting for business combinations in accordance with ASC Topic 805, "Business Combinations." The following table represents the allocation of the total consideration transferred in the TRP Exchange to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date. The purchase price allocation was completed in December 2025.

The following table sets forth the Company's purchase price allocation (in millions):

Total consideration	$	1,345
Fair value of liabilities assumed:		
Suspense liabilities	$	(8)
Fair value of assets acquired:		
Oil and natural gas properties		1,353
Net assets acquired and liabilities assumed	$	1,345

With the completion of the TRP Exchange, the Company acquired proved properties of $851 million and unproved properties of $502 million.

The results of operations attributable to the TRP Exchange since the acquisition date have been included in the consolidated statements of operations and were insignificant for the year ended December 31, 2024.

Endeavor Acquisition

On September 10, 2024, the Company completed its acquisition of Endeavor Parent, LLC ("Endeavor") (the "Endeavor Acquisition") for consideration consisting of (i) $7.1 billion in cash paid to the Endeavor equityholders, (ii) $238 million for the repayment of Endeavor's net debt, which included the $219 million net debt position and the associated $19 million make-whole premium paid upon redemption of the senior notes and costs incurred to terminate Endeavor's revolving credit facility, and (iii) approximately 117.27 million shares of the Company's common stock. The Endeavor Acquisition included approximately 500,849 gross (361,927 net) acres, which are primarily located in the Permian Basin. Following the Endeavor Acquisition, the Company believes its inventory has industry-leading depth and quality that will be converted into cash flow with the industry's lowest cost structure, creating a differentiated value proposition for Diamondback stockholders.

The cash consideration for the Endeavor Acquisition was funded through a combination of cash on hand, the net proceeds from the Company's April 2024 Notes offering and borrowings under the Tranche A Loans. Immediately following the close of the Endeavor Acquisition, Endeavor equityholders held approximately 39.8% of Diamondback's common stock. As of December 31, 2025, Endeavor's equityholders held approximately 35.8% of the Company's common stock.

Following the closing of the Endeavor Acquisition, the Company filed with the SEC a shelf registration statement, which became immediately effective upon filing, registering for resale the shares of common stock issued in the Endeavor Acquisition, as required by the terms of the related registration rights agreement.

The following table presents the acquisition consideration paid to Endeavor equityholders in the Endeavor Acquisition (in millions, except per share data, shares in thousands):

Consideration:		
Shares of Diamondback common stock issued at closing		117,267
Closing price per share of Diamondback common stock on the closing date	$	171.49
Fair value of Diamondback common stock issued	$	20,110
Base cash amount	$	8,000
Preliminary closing adjustments		(928)
Cash consideration to Endeavor equityholders		7,072
Cash payment of net debt position and make-whole amount		238
Total cash consideration		7,310
Total consideration (including fair value of Diamondback common stock issued)	$	27,420

Purchase Price Allocation

The Endeavor Acquisition was accounted for under the acquisition method of accounting for business combinations in accordance with ASC Topic 805, “Business Combinations.” The following table represents the allocation of the total purchase price for the acquisition of Endeavor to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date. The purchase price allocation was completed in September 2025.

The following table sets forth the Company’s purchase price allocation (in millions):

Total consideration	$	27,420
Fair value of liabilities assumed:		
Accounts payable - trade	$	18
Accrued capital expenditures		225
Other accrued liabilities		524
Revenues and royalties payable		567
Derivative instruments		5
Income taxes payable		223
Other current liabilities		25
Asset retirement obligations		267
Deferred income taxes		7,249
Other long-term liabilities		5
Amount attributable to liabilities acquired	$	9,108
Fair value of assets acquired:		
Accounts receivable - joint interest and other, net	$	63
Accounts receivable - oil and natural gas sales, net		659
Inventories		77
Derivative instruments		25
Prepaid expenses and other current assets		20
Oil and natural gas properties		34,805
Other property, equipment and land		849
Other assets		30
Amount attributable to assets acquired		36,528
Net assets acquired and liabilities assumed	$	27,420

The purchase price allocation above is based on the fair values of the assets and liabilities of Endeavor as of the closing date of the Endeavor Acquisition. The majority of the value of assets acquired and liabilities assumed was measured based on inputs that are not observable in the market and are therefore considered Level 3 inputs. The fair value of acquired property and equipment is based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets. Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production and mineral interest forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The value of derivative instruments was based on observable inputs including forward commodity-price curves which are considered Level 2 inputs. Deferred income taxes represent the tax effects of differences in the tax basis and acquisition-date fair values of assets acquired and liabilities assumed. The fair values of asset retirement obligations and inventories were calculated in accordance with the Company’s internal policies as described in Note 2—Summary of Significant Accounting Policies. The fair values of various current assets and liabilities including accounts receivable and accounts payable approximate their carrying values on the closing date of the Endeavor Acquisition because of the short-term nature of the instruments.

With the completion of the Endeavor Acquisition, the Company acquired proved properties of $20.6 billion and unproved properties of $14.2 billion, primarily in the Midland Basin.

The results of operations attributable to the Endeavor Acquisition since the acquisition date have been included in the consolidated statements of operations and include $1.8 billion of total revenue and $459 million of net income for the year ended December 31, 2024.

WTG Midstream Transaction

The Company owns a 25% non-operating equity investment in Remuda Midstream Holdings LLC, referred to as the “WTG joint venture.” On July 15, 2024, the WTG joint venture sold its subsidiary, WTG Midstream LLC, (the “WTG Midstream Transaction”) for which the Company received as its portion of the consideration 10.1 million common units issued by Energy Transfer LP (NYSE: ET) and $190 million in cash, subject to customary post-closing adjustments. The common unit consideration was also subject to preferred distributions to incentive members of the WTG joint venture which reduced the proceeds attributable to the Company. At the closing of the WTG Midstream Transaction, the value attributable to the Company of the 10.1 million common units was approximately $135 million, of which approximately $81 million was received by the Company and $54 million was initially held in escrow pursuant to an escrow agreement entered into by the WTG joint venture in connection with the initial transaction. In the third quarter of 2025, the Company received approximately $15 million related to the settlement of working capital and the full $54 million of the escrow amount was released. The total value of distributions received by the Company of $336 million, including certain post-closing adjustments, exceeded the carrying value of the Company’s investment balance in the WTG joint venture, resulting in an aggregate gain of approximately $139 million, of which approximately $65 million was recognized during the year ended December 31, 2025, respectively. The gain is included in the caption “Other income (expense), net” in the consolidated statement of operations.

Viper Acquisitions

Viper Tumbleweed Acquisitions

In September and October of 2024, Viper completed a series of related acquisitions including the Viper TWR Acquisition, the Viper Q Acquisition and the Viper M Acquisition, (collectively the “Viper Tumbleweed Acquisitions”) each as defined and discussed below. The Viper Tumbleweed Acquisitions were each accounted for as asset acquisitions in accordance with ASC Topic 805, “Business Combinations.”

On October 1, 2024, Viper acquired all of the issued and outstanding equity interests in TWR IV, LLC and TWR IV SellCo, LLC from Tumbleweed Royalty IV, LLC (“TWR IV”) and TWR IV SellCo Parent, LLC (the “Viper TWR Acquisition”), pursuant to a definitive purchase and sale agreement for consideration consisting of (i) approximately $464 million in cash, including transaction costs and certain customary post-closing adjustments, (ii) approximately 10.09 million Viper LLC units to TWR IV, (iii) an option granted to TWR IV to acquire up to 10.09 million shares of Viper’s Class B common stock (the “TWR Class B Option”), and (iv) contingent cash consideration of $16 million paid in January 2026 based on the average price of WTI sweet crude oil prompt month futures contracts for the calendar year 2025 (the “WTI 2025 Average”).

TWR IV can exchange some or all of its Viper LLC units for an equal number of shares of Viper’s Class A common stock. The mineral and royalty interests acquired in the Viper TWR Acquisition represent approximately 3,067 net royalty acres located primarily in the Permian Basin. Viper funded the cash consideration for the Viper TWR Acquisition through a combination of cash on hand, borrowings under Viper’s then revolving credit facility and proceeds from the Viper 2024 Equity Offering (as defined and discussed in Note 9—Stockholders’ Equity and Earnings (Loss) Per Share).

On September 3, 2024, Viper acquired all of the issued and outstanding equity interests in Tumbleweed-Q Royalties, LLC (the “Viper Q Acquisition”), pursuant to a definitive purchase and sale agreement for consideration consisting of (i) approximately $114 million in cash, including transaction costs and certain customary post-closing adjustments, and (ii) contingent cash consideration of $2 million paid in January 2026 based on the WTI 2025 Average.

Additionally, on September 3, 2024, Viper acquired all of the issued and outstanding equity interests in MC TWR Royalties, LP and MC TWR Intermediate, LLC (the “Viper M Acquisition” and together with the Viper Q Acquisition, the “Viper Q & M Acquisitions”), pursuant to a definitive purchase and sale agreement for consideration consisting of (i) approximately $76 million in cash, including transaction costs and certain customary post-closing adjustments, and (ii) contingent cash consideration of $2 million paid in January 2026 based on the WTI 2025 Average. The mineral and royalty interests acquired in the Viper Q & M Acquisitions represent approximately 406 and 267 net royalty acres located primarily in the Permian Basin, respectively. Viper funded the cash consideration for the Viper Q & M Acquisitions through a combination of cash on hand and borrowings under Viper’s then revolving credit facility.

The contingent consideration liabilities for each of the Viper Tumbleweed Acquisitions discussed above are collectively referred to as the "2026 WTI Contingent Liability".

2023 Activity

Diamondback Acquisition and Divestitures

Lario Acquisition

On January 31, 2023, the Company closed on its acquisition of all leasehold interests and related assets of Lario Permian, LLC, a wholly owned subsidiary of Lario Oil and Gas Company, and certain associated sellers. The acquisition included approximately 25,000 gross (16,000 net) acres in the Midland Basin and certain related oil and gas assets (the "Lario Acquisition"), in exchange for consideration of 4.33 million shares of the Company's common stock and $814 million in cash, including customary post-closing adjustments. Approximately $113 million of the cash consideration was deposited in an indemnity holdback escrow account at closing and was distributed upon satisfactory settlement of any potential title defects on the acquired properties during the first quarter of 2024. The cash consideration for the Lario Acquisition was funded through a combination of cash on hand, a portion of the net proceeds from the Company's offering of 6.250% Senior Notes due 2053 and borrowings under the Company's revolving credit facility.

The following table presents the acquisition consideration paid in the Lario Acquisition (in millions, except per share data, shares in thousands):

Consideration:		
Shares of Diamondback common stock issued at closing		4,330
Closing price per share of Diamondback common stock on the closing date	$	146.12
Fair value of Diamondback common stock issued	$	633
Cash consideration		814
Total consideration (including fair value of Diamondback common stock issued)	$	1,447

Purchase Price Allocation

The Lario Acquisition was accounted for as a business combination using the acquisition method. The following table represents the allocation of the total purchase price paid in the Lario Acquisition to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date. The purchase price allocation was completed in December 2023.

The following table sets forth the Company's purchase price allocation (in millions):

Total consideration	$	1,447
Fair value of liabilities assumed:		
Other long-term liabilities	$	37
Fair value of assets acquired:		
Oil and natural gas properties	$	1,460
Inventories		2
Other property, equipment and land		22
Amount attributable to assets acquired		1,484
Net assets acquired and liabilities assumed	$	1,447

Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The fair value of acquired midstream assets, vehicles and a field office were based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets and were included in the Company's consolidated balance sheets under the caption "Other property, equipment and land." The majority of the measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and are therefore considered Level 3 inputs in the fair value hierarchy.

With the completion of the Lario Acquisition, the Company acquired proved properties of $924 million and unproved properties of $536 million. The results of operations attributable to the Lario Acquisition since the acquisition date have been included in the consolidated statements of operations and include $488 million of total revenue and $200 million of net income for the year ended December 31, 2023.

Divestiture of Deep Blue Water Assets and Deep Blue Formation

On September 1, 2023, the Company closed on a joint venture agreement with Five Point Energy LLC ("Five Point") to form Deep Blue. At closing, the Company contributed certain treated water, fresh water and saltwater disposal assets (the "Deep Blue Water Assets") with a net carrying value of $703 million, including certain post-closing adjustments, and Five Point contributed $251 million in cash to Deep Blue. In exchange for these contributions, Deep Blue issued the Company a one-time cash distribution of approximately $516 million and a 30% equity ownership and voting interest, and issued to Five Point a 70% equity ownership and voting interest. Five Point is not considered a related party of the Company.

Additionally, under a separate agreement with Deep Blue, the Company continued to operate the Deep Blue Water Assets on a short-term basis. Five Point agreed to pay the Company approximately $47 million upon the successful transfer of operations to Deep Blue and the Company recorded approximately $43 million as a contingent consideration receivable on the closing date based on the assessed probability of earning the additional consideration. Upon the successful transfer of operations in June 2024, the Company received the full contingent consideration amount of $47 million.

The Company recorded its 30% equity interest in Deep Blue at fair value based on the cash consideration and contingent consideration contributed by Five Point to Deep Blue in exchange for its 70% equity ownership. The Company's equity method investment in Deep Blue had an initial fair value of $126 million. The Company's proportionate share of the income or loss from Deep Blue is recognized on a two-month lag. The Company has recognized an aggregate $13 million loss on the sale of its Deep Blue Water Assets, of which approximately $1 million was recognized during the year ended December 31, 2024. The loss on the sale of Deep Blue Water Assets is included in the caption "Other operating expenses" in the consolidated statement of operations. The majority of measurements utilized to determine the fair value amounts reported above relating to this transaction are based on inputs that are not observable in the market and are therefore considered Level 3 inputs in the fair value hierarchy.

The Company and Five Point anticipate collectively contributing $500 million in follow-on capital to fund future growth projects and acquisitions.

As part of the transaction, the Company also entered into a 15-year dedication with Deep Blue for its produced water and supply water within a 12-county area of mutual interest in the Midland Basin. See Note 7—Related Party Transactions for further discussion of transactions with Deep Blue.

Equity Method Investment Divestitures

During 2023, the Company divested its 43% limited liability company interest in OMOG JV LLC and its 10% non-operating equity investment in Gray Oak Pipeline, LLC for an aggregate $397 million. These divestitures resulted in an aggregate gain on the sale of equity method investments of approximately $88 million, which is included in the caption "Other income (expense), net" on the consolidated statements of operations for the year ended December 31, 2023. The Company used its net proceeds from this transaction for debt reduction and other general corporate purposes.

Non-Core Asset Divestitures

During 2023, the Company divested non-core assets to unrelated third-party buyers consisting of approximately 19,000 net acres in Glasscock County, TX and 4,900 net acres in Ward County and Winkler County, TX for net cash proceeds of $341 million, including customary post-closing adjustments. The Company used its net proceeds from these transactions for debt reduction and other general corporate purposes.

The divestitures of non-core oil and gas assets did not result in a significant alteration of the relationship between the Company's capitalized costs and proved reserves and, accordingly, the Company recorded the proceeds as a reduction of its full cost pool with no gain or loss recognized on the sales.

Viper Acquisitions

GRP Acquisition

On November 1, 2023, Viper acquired certain mineral and royalty interests from Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings, LP, affiliates of Warwick Capital Partners and GRP Energy Capital, pursuant to a definitive purchase and sale agreement for approximately 9.02 million Viper common units and $747 million in cash, including transaction costs and certain customary post-closing adjustments (the "GRP Acquisition"). The mineral and royalty interests acquired in the GRP Acquisition represent approximately 4,600 net royalty acres in the Permian Basin, plus approximately 2,700 additional net royalty acres in other major basins. The cash consideration for the GRP Acquisition was funded through a combination of cash on hand and held in escrow, borrowings under Viper's then revolving credit facility, proceeds from the Viper 2031 Notes (as defined and discussed in Note 8—Debt) and proceeds from a $200 million common unit issuance to Diamondback discussed further in Note 9—Stockholders' Equity and Earnings (Loss) Per Share.

Pro Forma Financial Information (Unaudited)

The following unaudited summary pro forma financial information for the years ended December 31, 2024 and 2023 has been prepared to give effect to (i) the Endeavor Acquisition as if it had occurred on January 1, 2023, and (ii) the TRP Exchange as if it had occurred on January 1, 2023. The unaudited pro forma financial information does not purport to be indicative of what the combined company's results of operations would have been if the transaction had occurred on the dates indicated, nor is it indicative of the future financial position or results of operations of the combined company.

The below information reflects pro forma adjustments for the issuance of the Company's common stock as consideration for the Endeavor Acquisition, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including adjustments to depreciation, depletion and amortization based on the full cost method of accounting.

Additionally, pro forma earnings for the year ended December 31, 2024 include historical acquisition-related costs incurred by Endeavor of $415 million, which consist primarily of incentive compensation, investment banking and legal costs. The Company incurred acquisition related costs of $303 million for the year ended December 31, 2024 which consist primarily of $197 million in severance and accelerated incentive compensation payments to former Endeavor employees, $78 million in investment banking and legal costs incurred upon the closing of the Endeavor Acquisition, $14 million related to regulatory reviews under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and other individually insignificant items including SEC filing fees and other professional fees. The Company incurred acquisition costs of $42 million in connection with the Endeavor Acquisition for the year ended December 31, 2025, which primarily consist of severance and accelerated incentive compensation payments to former Endeavor employees. The Company incurred acquisition related costs of $10 million for the year ended December 31, 2025, which primarily consist of advisory and legal fees related to the TRP Exchange. The pro forma results of operations do not include any cost savings or other synergies that may result from the Endeavor Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired 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.

	Year Ended December 31,	
	2024	2023
	(In millions, except per share amounts)	
Revenues	$ 15,706	$ 14,618
Income (loss) from operations	$ 6,448	$ 7,787
Net income (loss) attributable to Diamondback Energy, Inc.	$ 3,315	$ 5,668
Basic earnings (loss) per common share	$ 11.19	$ 18.95
Diluted earnings (loss) per common share	$ 11.19	$ 18.95

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following as of the dates indicated:

	December 31,	
	2025	2024
	(In millions)	
Oil and natural gas properties:		
Proved properties	$ 71,588	$ 59,574
Unproved properties	23,941	22,666
Gross oil and natural gas properties	95,529	82,240
Accumulated depletion	(15,974)	(11,083)
Accumulated impairment	(11,606)	(7,954)
Oil and natural gas properties, net	67,949	63,203
Other property, equipment and land	874	1,440
Accumulated depreciation, amortization, accretion and impairment	(202)	(171)
Total property and equipment, net	$ 68,621	$ 64,472

The following table presents the balance of costs not subject to depletion as of December 31, 2025 by the period in which the costs were incurred:

	2025	2024	2023	Prior	Total
	(In millions)				
Balance of costs not subject to depletion:					
Acquisition costs	$ 4,528	$ 12,821	$ 1,043	$ 4,456	$ 22,848
Capitalized interest	564	220	111	101	996
Development costs	97	—	—	—	97
Total not subject to depletion	$ 5,189	$ 13,041	$ 1,154	$ 4,557	$ 23,941

Costs associated with unevaluated properties are not subject to depletion and excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. Although the evaluation process has not been completed on our unevaluated properties, the Company currently estimates these costs will be added to the amortization base within fifteen years.

The Company capitalized internal costs of approximately $102 million, $90 million and $66 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter which determines a limit, or ceiling, on the book value of proved oil and natural gas properties. As a result of the decline in commodity prices during 2025, the Company recorded a non-cash ceiling test impairment for the year ended December 31, 2025 of $3.7 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. No impairment expense was recorded for the years ended December 31, 2024 and 2023.

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 future trailing 12-month commodity prices decline as compared to the commodity prices used in prior quarters, the Company may have material write downs in subsequent quarters. 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.

6. 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,	
	2025	2024
	(In millions)	
Asset retirement obligations, beginning of period	$ 592	$ 245
Additional liabilities incurred	50	8
Liabilities acquired	15	278
Liabilities settled and divested	(153)	(37)
Accretion expense	35	22
Revisions in estimated liabilities	3	76
Asset retirement obligations, end of period	542	592
Less: current portion[(1)]	31	19
Asset retirement obligations - long-term[(2)]	$ 511	$ 573

(1) The current portion of the asset retirement obligation is included in the caption "Other accrued liabilities" in the Company's consolidated balance sheets.
(2) The long-term portion of the asset retirement obligation is included in the caption "Other long-term 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.

7. RELATED PARTY TRANSACTIONS

Related Party Transactions

Deep Blue

The Company considers its equity method investments to be related parties. At December 31, 2025, the Company's only significant equity method investment was its 30% equity ownership interest in Deep Blue, which is included in the caption "Other assets" on the Company's consolidated balance sheets. Additionally, the Company has other related party transactions with Deep Blue in the ordinary course of business, which result in (i) certain accounts receivable due from Deep Blue, (ii) accrued capital expenditures and other accrued payables related to a commitment to fund certain capital expenditures on projects that were in process at the time of the Deep Blue transaction, and (iii) lease operating expenses and capitalized expenses related to fees paid to Deep Blue under a 15-year dedication for its produced water and supply water within a 12-county area of mutual interest in the Midland Basin.

For further discussion on additional transactions with Deep Blue, see Note 4—Acquisitions and Divestitures.

The following table presents related party balances that pertain to Deep Blue which are included in the consolidated balance sheets at December 31, 2025 and 2024:

	December 31,	
	2025	2024
	(In millions)	
Assets:		
Accounts receivable	$ 1	$ 5
Other assets	$ 197	$ 137
Liabilities:		
Accounts payable and accrued capital expenditures	$ 71	$ 31
Other accrued liabilities	$ 82	$ 22

During the years ended December 31, 2025 and 2024, the Company recorded approximately $199 million and $135 million, respectively, for water services provided by Deep Blue during the completion phase of wells. These costs were capitalized and any remaining unamortized costs are included in the caption “Oil and natural gas properties” on the consolidated balance sheets.

The following table presents the significant related party transactions included in the consolidated statements of operations for the years ended December 31, 2025 and 2024:

	Year Ended December 31,	
	2025	2024
	(In millions)	
Lease operating expenses	$ 175	$ 114

Viper

For discussion on related party transactions with Viper, see Note 4—Acquisitions and Divestitures—2025 Drop Down.

SGF Common Stock Repurchases

On November 28, 2025, the Company entered into a letter agreement with SGF FANG Holdings, LP (“SGF”). SGF includes certain Endeavor equityholders that received shares of the Company’s common stock as partial consideration for the Endeavor Acquisition, and as a result, is considered a related party of the Company under ASC Topic 850 “Related Party Disclosures.” The letter agreement provides SGF with the right, but not the obligation, to sell up to 3.0 million shares of the Company’s common stock to the Company per quarter through December 31, 2026 at the most recent Nasdaq closing price of such transaction, pursuant to the letter agreement. Pursuant to the letter agreement, on the same date, the Company agreed to repurchase 2.0 million shares of its common stock held by SGF at $152.59 per share. Repurchases under the letter agreement are pursuant to the Company’s existing share repurchase program, and have been approved by the audit committee of the Company’s board of directors. For details on the Company’s existing share repurchase program, see Note 9—Stockholders’ Equity and Earnings (Loss) Per Share. See Note 16—Subsequent Events for repurchases from SGF during the first quarter of 2026.

8. DEBT

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

	December 31, 2025	December 31, 2024
	(In millions)	
3.250% Senior Notes due 2026	$ 749	$ 750
5.625% Senior Notes due 2026[1]	14	14
5.200% Senior Notes due 2027	850	850
7.125% Medium-term Notes, Series B, due 2028	73	73
3.500% Senior Notes due 2029	915	915
5.150% Senior Notes due 2030	850	850
3.125% Senior Notes due 2031	740	767
6.250% Senior Notes due 2033	1,100	1,100
5.400% Senior Notes due 2034	1,300	1,300
5.550% Senior Notes due 2035	1,200	—
4.400% Senior Notes due 2051	386	650
4.250% Senior Notes due 2052	605	750
6.250% Senior Notes due 2053	650	650
5.750% Senior Notes due 2054	1,480	1,500
5.900% Senior Notes due 2064	1,000	1,000
Tranche A Loans	—	900
2025 Term Loan	550	—
Unamortized debt issuance costs	(99)	(91)
Unamortized discount costs	(22)	(25)
Unamortized premium costs	2	3
Unamortized basis adjustment of dedesignated interest rate swap agreements[2]	(59)	(72)
Viper revolving credit facility	105	261
Viper 5.375% Senior Notes due 2027 (discharged)	—	430
Viper 4.900% Senior Notes due 2030	500	—
Viper 7.375% Senior Notes due 2031	—	400
Viper 5.700% Senior Notes due 2035	1,100	—
Viper 2025 Term Loan	500	—
Total debt, net	14,489	12,975
Less: current maturities of debt	763	900
Total long-term debt	$ 13,726	$ 12,075

(1) QEP remained the issuer of these senior notes subsequent to becoming a wholly owned subsidiary of the Company.
(2) Represents the unamortized basis adjustment related to two receive-fixed, pay variable interest rate swap agreements which were previously designated as fair value hedges of the Company's 3.500% fixed rate senior notes due 2029 (the "2029 Notes"). This basis adjustment is being amortized to interest expense over the remaining term of the 2029 Notes utilizing the effective interest method. See Note 12—Derivatives for further discussion on the interest rate swaps.

Debt maturities as of December 31, 2025, excluding debt issuance costs, premiums and discounts and the unamortized basis adjustment of dedesignated interest rate swap agreements are as follows:

Year Ending December 31,	(In millions)
2026	$ 763
2027	1,900
2028	73
2029	915
2030	1,455
Thereafter	9,561
Total	$ 14,667

References in this section to the Company shall mean Diamondback Energy, Inc. and Diamondback E&P, collectively, unless otherwise specified.

Credit Agreement

On June 12, 2025, Diamondback E&P, as borrower, and Diamondback Energy, Inc., as parent guarantor, entered into a sixteenth amendment to the existing credit agreement (the “Credit Agreement”), which among other things (i) extended the maturity date to June 12, 2030, and (ii) decreased the interest rate as discussed below. The Credit Agreement provides for a maximum credit amount of $2.5 billion, which may be further increased to a total maximum commitment of $2.6 billion. As of December 31, 2025, the Company had no outstanding borrowings and approximately $2.5 billion available for future borrowings under the Credit Agreement. During the years ended December 31, 2025, 2024 and 2023, the weighted average interest rate on borrowings under the Credit Agreement was 5.60%, 6.33% and 6.31%, respectively.

After giving effect to the amendment, outstanding borrowings under the Credit Agreement bear interest at a per annum rate elected by Diamondback E&P that is equal to (i) term SOFR or (ii) an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50%, and 1-month term SOFR plus 1.0%, subject to a 1.0% floor), in each case plus the applicable margin. The applicable margin ranges from 0.000% to 0.750% per annum in the case of the alternate base rate and from 1.000% to 1.750% per annum in the case of term SOFR, in each case based on the pricing level, and the commitment fee ranges from 0.100% to 0.250% per annum on the average daily unused portion of the commitments, based on the pricing level. The pricing level depends on the Company’s long-term senior unsecured debt ratings.

The Credit Agreement contains a financial covenant that requires the Company to maintain a Total Net Debt to Capitalization Ratio (as defined in the Credit Agreement) of no more than 65%. As of December 31, 2025, the Company was in compliance with all financial maintenance covenants under the revolving credit facility, as then in effect.

Viper’s Revolving Credit Facility

On June 12, 2025, Former Viper, as guarantor, entered into a credit agreement with Viper LLC, as borrower, and Wells Fargo, as the administrative agent (the “Viper Revolving Credit Facility”), which among other things, provides the borrower with a senior unsecured revolving credit facility with a commitment of $1.5 billion. The Viper Revolving Credit Facility has a maturity date of June 12, 2030, with the ability to request three extensions of the maturity date by one year. The Viper Revolving Credit Facility was previously guaranteed by certain subsidiaries of the borrower, and upon completion of the Sitio Acquisition, those subsidiary guarantees were released and New Viper and Former Viper became co-guarantors. The Viper Revolving Credit Facility replaced the borrower’s previous revolving credit facility, dated July 20, 2018, among Viper, the borrower and Wells Fargo as amended, restated, amended and restated, supplemented or otherwise modified prior to June 12, 2025. As of December 31, 2025, there were $105 million in outstanding borrowings and $1.4 billion available for future borrowings under the Viper Revolving Credit Facility. During the years ended December 31, 2025, 2024 and 2023, respectively, the weighted average interest rates on borrowings under Viper’s respective revolving credit facilities were 6.02%, 7.34% and 7.41%.

Borrowings under the Viper Revolving Credit Facility bear interest at a per annum rate elected by the borrower that is equal to term SOFR or an alternate base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50% and 1-month term SOFR plus 1.0%, subject to a 1.0% floor), in each case plus the applicable margin. The applicable margin ranges from 0.125% to 1.000% per annum in the case of the alternative base rate loans and from 1.125% to 2.000% per annum in the case of term SOFR loans, in each case based on the pricing level. Further, the commitment fee ranges from 0.125% to 0.325% per annum on the average daily unused portion of the commitment, again based on the pricing level. The pricing level depends on the rating of Viper's long-term senior unsecured debt by certain ratings agencies.

The Viper Revolving Credit Facility contains a financial covenant that requires Viper to maintain a Total Net Debt to Capitalization Ratio (as defined in the Viper Revolving Credit Facility) of no more than 65%. As of December 31, 2025, the borrower was in compliance with all financial maintenance covenants under the Viper Revolving Credit Facility.

On December 23, 2025, Viper Energy Partners LLC converted its legal form (the "Viper LLC Conversion"), in accordance with the applicable laws of the State of Delaware, to a Delaware limited partnership named Viper Energy Partners LP ("Viper LP"), which is now the borrower under the Viper Revolving Credit Facility.

Term Loan Agreements

Diamondback Term Loan Agreements

2025 Term Loan

In connection with the Double Eagle Acquisition, Diamondback Energy, Inc., as guarantor, entered into a term loan credit agreement with Diamondback E&P, as borrower, and Bank of America, N.A., as administrative agent (the "2025 Term Loan") on March 21, 2025.

The 2025 Term Loan provided the Company with the ability to borrow up to $1.5 billion on an unsecured basis to fund a portion of the cash consideration and expenses for the Double Eagle Acquisition. On April 1, 2025, the date of closing of the Double Eagle Acquisition, the 2025 Term Loan was fully drawn in a single borrowing. Any then-outstanding amounts will mature and be payable in full on the second anniversary of the initial funding date.

During the year ended December 31, 2025, the weighted average interest rate on borrowings under the 2025 Term Loan was 5.64%.

Outstanding borrowings under the 2025 Term Loan bear interest at a per annum rate elected by the Company that is equal to (i) term SOFR plus 0.10% ("Adjusted Term SOFR") or (ii) an alternate base rate (which is equal to the greatest of (a) the Federal Funds effective rate plus 0.50%, (b) the prime rate, (c) Adjusted Term SOFR plus 1.0%, and (d) 1.0%), in each case plus the applicable margin. The applicable margin ranges from 0.125% to 1.000% per annum in the case of the alternate base rate and from 1.125% to 2.000% per annum in the case of Adjusted Term SOFR, in each case based on the pricing level, and the commitment fee is equal to 0.125% per annum on the aggregate principal amount of the commitments. The pricing level depends on the Company's long-term senior unsecured debt ratings.

Tranche A Loans

On February 29, 2024, Diamondback Energy, Inc., as guarantor, entered into a term loan credit agreement with Diamondback E&P, as borrower, and Citibank, N.A., as administrative agent, which at the time of borrowing was comprised of $1.0 billion of Tranche A Loans. The Tranche A Loans were fully drawn to fund a portion of the cash consideration for the Endeavor Acquisition.

On May 5, 2025, the Company used the cash proceeds received from the 2025 Drop Down to repay in full and terminate the $900 million remaining outstanding Tranche A Loans. During the years ended December 31, 2025 and 2024, the weighted average interest rate on borrowings under the Tranche A Loans was 5.87% and 6.13%, respectively.

Viper Term Loan Agreement

Viper 2025 Term Loan

On July 23, 2025, in connection with the Sitio Acquisition, Former Viper, as guarantor, entered into a term loan credit agreement with Viper LLC, as borrower, and Goldman Sachs Bank USA, as administrative agent, (the "Viper 2025 Term Loan").

The Viper 2025 Term Loan provided Viper with the ability to borrow up to $500 million on a senior unsecured basis to fund a portion of the retirement of Sitio's net debt, in connection with the Sitio Acquisition. On August 19, 2025, the date of closing of the Sitio Acquisition, the Viper 2025 Term Loan was fully drawn in a single borrowing. Any then-outstanding amounts will mature and be payable in full on the second anniversary of the initial funding date. In connection with the closing of the Sitio Acquisition, New Viper became a co-guarantor of the Viper 2025 Term Loan. During the year ended December 31, 2025, the weighted average interest rate on borrowings under the Viper 2025 Term Loan was 5.72%.

Borrowings under the Viper 2025 Term Loan bear interest at a per annum rate elected by the borrower that is equal to SOFR or an alternate base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50% and 1-month term SOFR plus 1.0%, subject to a 1.0% floor), in each case plus the applicable margin. The applicable margin ranges from 0.250% to 1.125% per annum in the case of the alternate base rate loans and from 1.250% to 2.125% per annum in the case of term SOFR loans, in each case based on the pricing level. The pricing level depends on the rating of Viper's long-term senior unsecured debt by certain ratings agencies. In addition, the fee on undrawn commitments is equal to 0.20% per annum on the aggregate principal amount of such commitments.

Following the Viper LLC Conversion, Viper LP, as successor to Viper Energy Partners LLC, became the borrower under the Viper 2025 Term Loan.

Issuance of Notes

2025 Issuance of Notes

Diamondback Senior Notes

On March 20, 2025, the Company issued $1.2 billion aggregate principal amount of 5.550% Senior Notes due April 1, 2035 (the "2035 Notes"), which are included in the Company's Guaranteed Senior Notes. The Company received net proceeds of $1.19 billion, after underwriters' discounts and transaction costs. Interest on the 2035 Notes is payable semi-annually on April 1 and October 1 of each year, which commenced on October 1, 2025. The Company used the net proceeds to fund a portion of the cash consideration for the Double Eagle Acquisition.

Viper Senior Notes

On July 23, 2025, Viper LLC, as issuer, and Former Viper, as guarantor, issued $1.6 billion in aggregate principal amount of senior notes consisting of (i) $500 million aggregate principal amount of 4.900% Senior Notes due August 1, 2030 (the "Viper 2030 Notes"), and (ii) $1.1 billion aggregate principal amount of 5.700% Senior Notes due August 1, 2035 (the "Viper 2035 Notes" and together with the Viper 2030 Notes, the "Viper 2025 Notes"). Viper received net proceeds of approximately $1.58 billion, after underwriters' discounts and transaction costs. Interest on the Viper 2025 Notes is payable semi-annually in February and August of each year, beginning on February 1, 2026. Concurrently, Viper used approximately $824 million of the proceeds to redeem approximately $780 million in aggregate principal amounts of the Viper Notes, including accrued interest due and applicable redemption premiums. Following the closing of the Sitio Acquisition, Viper used the remaining proceeds from the issuance of the Viper 2025 Notes to (i) retire Sitio's 7.875% senior notes due 2028, (ii) partially repay borrowings under Sitio's revolving credit facility, (iii) pay fees, costs and expenses related to the redemption or repayment of such debt, and (iv) for general corporate purposes. The Viper 2025 Notes have been registered under the Securities Act. Following the Viper LLC Conversion, Viper LP, as successor to Viper Energy Partners LLC, became the issuer with respect to the Viper 2025 Notes.

2024 Issuance of Notes

On April 18, 2024, Diamondback Energy, Inc., as borrower, and Diamondback E&P, as guarantor, issued an aggregate of $5.5 billion in senior notes, consisting of (i) $850 million aggregate principal amount of 5.200% Senior Notes due April 18, 2027 (the “2027 Notes”), (ii) $850 million aggregate principal amount of 5.150% Senior Notes due January 30, 2030 (the “2030 Notes”), (iii) $1.3 billion aggregate principal amount of 5.400% Senior Notes due April 18, 2034 (the “2034 Notes”), (iv) $1.5 billion aggregate principal amount of 5.750% Senior Notes due April 18, 2054 (the “2054 Notes”), and (v) $1.0 billion aggregate principal amount of 5.900% Senior Notes due April 18, 2064 (the “2064 Notes” and together with the 2027 Notes, the 2030 Notes, the 2034 Notes and the 2054 Notes, the “April 2024 Notes”). The April 2024 Notes are included in the Company’s Guaranteed Senior Notes. The Company received net proceeds of $5.5 billion, after underwriters’ discounts and transaction costs. Interest on the 2030 Notes is payable semi-annually on January 30 and July 30 of each year, beginning on July 30, 2024. Interest on each other series of notes will be payable semi-annually on April 18 and October 18 of each year. The Company used the net proceeds from the April 2024 Notes to fund a portion of the cash consideration for the Endeavor Acquisition.

Retirement of Notes

Diamondback Retirement of Notes

During the year ended December 31, 2025, the Company opportunistically repurchased an aggregate principal amount of approximately $455 million of its senior notes, which consisted of $27 million of the 3.125% Senior Notes due 2031, $263 million of the 4.400% Senior Notes due 2051, $145 million of the 4.250% Senior Notes due 2052 and $20 million of the 5.750% Senior Notes due 2054, in open market transactions for total cash consideration, including accrued interest paid, of approximately $363 million, at an average of 79.3% of par value. These repurchases resulted in a gain on extinguishment of debt of approximately $88 million during the year ended December 31, 2025.

During the year ended December 31, 2024, the Company opportunistically repurchased an aggregate principal amount of approximately $28 million of its senior notes, which consisted of $22 million of its 3.125% Senior Notes due 2031 and $6 million of its 3.500% Senior Notes due 2029 for total cash consideration, including accrued interest paid of $25 million. These repurchases resulted in an immaterial gain on extinguishment of debt during the year ended December 31, 2024.

Viper Retirement of Notes

During the second quarter of 2025, Viper opportunistically repurchased principal amounts of $50 million of its 5.375% Senior Notes due 2027 (the “Viper 2027 Notes”) in open market transactions for total cash consideration of $50 million, at an average of 99.7% of par value, resulting in an immaterial gain on extinguishment of debt for the year ended December 31, 2025.

On July 23, 2025, using proceeds from the issuance of the Viper 2025 Notes, Viper (i) redeemed all of its outstanding 7.375% Senior Notes maturing on November 1, 2031, (the “Viper 2031 Notes”), which were issued in October 2023 to partially fund the cash portion of the GRP Acquisition, for total cash consideration of approximately $434 million including the applicable redemption premium of 106.8% of par and accrued and unpaid interest up to, but not including, the redemption date, and (ii) deposited approximately $390 million to redeem all of its outstanding Viper 2027 Notes on November 1, 2025, for total cash consideration, including payment of interest due to, but not including, the redemption date at a redemption price equal to 100% of the principal amount of the Viper 2027 Notes. The redemption of the Viper 2031 Notes resulted in a loss on extinguishment of debt of $32 million.

Guaranteed Senior Notes

The Guaranteed Senior Notes are the Company’s senior unsecured obligations and are fully and unconditionally guaranteed by Diamondback E&P, are senior in right of payment to any of the Company’s future subordinated indebtedness and rank equal in right of payment with all of the Company’s existing and future senior indebtedness.

The Viper 2025 Notes (i) are senior unsecured obligations and are fully and unconditionally guaranteed by Former Viper, and, following the closing of the Sitio Acquisition, also by New Viper, (ii) are senior in right of payment to any of Viper’s future subordinated indebtedness, and (iii) rank equal in right of payment with all of Viper’s existing and future senior indebtedness. The Company does not guarantee the Viper 2025 Notes. In the future, each of Viper's restricted subsidiaries that either (i) guarantees any of its or a guarantor's indebtedness, or (ii) is a domestic restricted subsidiary and is an obligor with respect to any indebtedness under any credit facility will be required to guarantee the Viper 2025 Notes.

Interest Expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2025, 2024 and 2023:

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Interest expense	$ 837	$ 624	$ 346
Other fees and expenses	4	3	2
Less: interest income	25	156	18
Less: capitalized interest	572	336	171
Interest expense, net	$ 244	$ 135	$ 159

9. STOCKHOLDERS' EQUITY AND EARNINGS (LOSS) PER SHARE

Common Stock Repurchase Program

The Company's board of directors has approved a common stock repurchase program to acquire up to $8.0 billion of the Company's outstanding common stock, excluding excise tax. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable regulatory and legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. During the years ended December 31, 2025, 2024 and 2023, the Company repurchased approximately $2.0 billion, which includes $305 million for the repurchase of 2.0 million shares from SGF, $959 million and $838 million of common stock under the repurchase program, respectively, in each case excluding excise tax. For further discussion on the repurchase from SGF, see Note 7—Related Party Transactions. As of December 31, 2025, approximately $2.7 billion remained available for future repurchases under the Company's repurchase program, excluding excise tax.

Viper's Repurchase Program

Previously, Viper's board of directors approved a repurchase program to acquire up to $750 million of Viper's outstanding Class A common stock, excluding excise tax, over an indefinite period of time. On December 10, 2025, Viper's board of directors expanded the repurchase program to also include repurchases of Viper's outstanding Class B common stock and Viper LLC units, in each case excluding excise tax. During the year ended December 31, 2025, Viper repurchased approximately $194 million under its repurchase program, excluding excise tax. During the year ended December 31, 2024, Viper had no repurchases under its repurchase program and during the year ended December 31, 2023, Viper repurchased approximately $95 million under its repurchase program, excluding excise tax. As of December 31, 2025, $241 million remains available under Viper's repurchase program, excluding excise tax.

Viper 2025 Equity Offering

On February 3, 2025, Viper completed an underwritten public offering of approximately 28.34 million shares of Viper's Class A common stock, which included approximately 3.70 million shares issued pursuant to an option to purchase additional shares of Viper's Class A common stock granted to the underwriters, at a price to the public of $44.50 per share for total net proceeds to Viper of approximately $1.2 billion, after the underwriters' discount and transaction costs (the "Viper 2025 Equity Offering"). The net proceeds were used to fund (i) a portion of Viper's cash consideration for the 2025 Drop Down, (ii) cash consideration for other acquisitions, and (iii) for general corporate purposes.

Viper 2024 Equity Offering

On September 13, 2024, Viper completed an underwritten public offering of approximately 11.5 million shares of Viper's Class A common stock, which included 1.5 million shares issued pursuant to an option to purchase additional shares of Viper's Class A common stock granted to the underwriters, at a price to the public of $42.50 per share for total net proceeds to Viper of approximately $476 million, after the underwriters' discount and transaction costs (the "Viper 2024 Equity Offering"). The net proceeds were used to fund a portion of the cash consideration for the Viper TWR Acquisition.

Change in Ownership of Consolidated Subsidiaries

Non-controlling interests in the accompanying consolidated financial statements represent interests in Viper held by parties other than the Company and are presented as a component of equity. When the Company's relative ownership interests in Viper change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, will occur.

The following table summarizes changes in the ownership interest in consolidated subsidiaries during the respective periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Net income (loss) attributable to the Company	$ 1,664	$ 3,338	$ 3,143
Change in ownership of consolidated subsidiaries	(444)	(62)	77
Change from net income (loss) attributable to the Company's stockholders and transfers with non-controlling interest	$ 1,220	$ 3,276	$ 3,220

Dividends

The following table presents dividends and distribution equivalent rights paid on the Company’s common stock during the respective periods:

	Base	Variable	Total Per Share	Total
		(In per share)		(In millions)
2025				
First quarter	$ 1.00	$ —	$ 1.00	$ 291
Second quarter	1.00	—	1.00	293
Third quarter	1.00	—	1.00	291
Fourth quarter	1.00	—	1.00	288
Total year-to-date	$ 4.00	$ —	$ 4.00	$ 1,163
2024				
First quarter	$ 0.90	$ 2.18	$ 3.08	$ 552
Second quarter	0.90	1.07	1.97	355
Third quarter	0.90	1.44	2.34	419
Fourth quarter	0.90	—	0.90	263
Total year-to-date	$ 3.60	$ 4.69	$ 8.29	$ 1,589
2023				
First quarter	$ 0.80	$ 2.15	$ 2.95	$ 546
Second quarter	0.80	0.03	0.83	151
Third quarter	0.84	—	0.84	151
Fourth quarter	0.84	2.53	3.37	607
Total year-to-date	$ 3.28	$ 4.71	$ 7.99	$ 1,455

Dividends to Non-Controlling Interest

During the years ended December 31, 2025, 2024 and 2023, Viper paid $382 million, $227 million and $129 million of dividends/distributions to its public shareholders, excluding Diamondback, in accordance with the dividend policy approved by its board of directors. These dividends are reflected under the caption “Dividends/distributions to non-controlling interest” on the Company’s consolidated statements of stockholders’ equity and consolidated statements of cash flows.

Earnings (Loss) Per Share

The Company’s earnings (loss) per share amounts have been computed using the two-class method. The two-class method is an earnings allocation proportional to the respective ownership among holders of common stock and participating securities. Basic earnings (loss) 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 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 (loss) per common share is presented below:

	Year Ended December 31,		
	2025	2024	2023
	(In millions, except per share amounts)		
Net income (loss) attributable to common shares	$ 1,664	$ 3,338	$ 3,143
Less: distributed and undistributed earnings allocated to participating securities[(1)]	8	21	22
Net income (loss) attributable to common stockholders	$ 1,656	$ 3,317	$ 3,121
Weighted average common shares outstanding:			
Basic weighted average common shares outstanding	289,079	213,545	179,999
Effect of dilutive securities:			
Weighted-average potential common shares issuable	—	—	—
Diluted weighted average common shares outstanding	289,079	213,545	179,999
Basic net income (loss) attributable to common shares	$ 5.73	$ 15.53	$ 17.34
Diluted net income (loss) attributable to common shares	$ 5.73	$ 15.53	$ 17.34

(1) Unvested restricted stock units and performance-based restricted stock unit awards that contain non-forfeitable distribution equivalent rights are considered participating securities and therefore are included in the earnings per share calculation pursuant to the two-class method.

10. EQUITY-BASED COMPENSATION

Under the Equity Plan approved by the board of directors, the Company is authorized to issue up to 11.8 million shares of incentive and non-statutory stock options, restricted stock awards and restricted stock units, performance awards and stock appreciation rights to eligible employees. The Company currently has outstanding restricted stock units and performance-based restricted stock units under the Equity Plan. At December 31, 2025, approximately 3.80 million shares of common stock remain available for future grants under the Equity Plan. The Company classifies its restricted stock units and performance-based restricted stock units as equity-based awards and 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.

In addition to the Equity Plan, Viper maintains its own long-term incentive plan, which is not significant to the Company.

The following table presents the financial statement impacts of equity compensation plans and related costs on the Company’s financial statements:

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
General and administrative expenses	$ 81	$ 65	$ 54
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	$ 33	$ 30	$ 26

Restricted Stock Units

The following table presents the Company’s restricted stock unit activity during the year ended December 31, 2025 under the Equity Plan:

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2024	645,408	$ 159.84
Granted	722,623	$ 148.86
Vested	(400,017)	$ 154.66
Forfeited	(77,952)	$ 152.86
Unvested at December 31, 2025	890,062	$ 153.87

The aggregate grant date fair value of restricted stock units that vested during the years ended December 31, 2025, 2024 and 2023 was $62 million, $57 million and $48 million, respectively. As of December 31, 2025, the Company’s unrecognized compensation cost related to unvested restricted stock units was $105 million, which is expected to be recognized over a weighted-average period of 2.1 years.

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 TSR of the Company’s common stock as compared to a designated peer group during a three-year performance period.

In March 2025, eligible employees received performance restricted stock unit awards totaling 171,638 units from which a minimum of 0% and a maximum of 200% of the units could be awarded based upon the measurement of TSR of the Company’s common stock as compared to a designated peer group during the three-year performance period of January 1, 2025 to December 31, 2027, and cliff vest at December 31, 2027, subject to continued employment. The initial payout of the March 2025 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%. Additionally, in May 2025 the Company granted 14,881 performance restricted stock units under substantially the same terms as the March 2025 performance restricted stock unit awards.

In March 2024, eligible employees received performance restricted stock unit awards totaling 110,989 units from which a minimum of 0% and a maximum of 200% of the units could be awarded based upon the measurement of TSR of the Company’s common stock as compared to a designated peer group during the three-year performance period of January 1, 2024 to December 31, 2026 and cliff vest at December 31, 2026 subject to continued employment. The initial payout of the March 2024 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%. Additionally, in September 2024 the Company granted 6,750 units under substantially the same terms as the March 2024 performance restricted stock unit awards.

In March 2023, eligible employees received performance restricted stock unit awards totaling 126,347 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, 2023 to December 31, 2025. These awards cliff vested at 200% on December 31, 2025 based upon the outcome of the TSR during the performance period, which did not result in a further TSR modifier being applied. Additionally, in July 2023 the Company granted 1,858 units under substantially the same terms as the March 2023 performance restricted stock unit awards.

The fair value of each performance restricted stock unit issuance 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 and the related assumptions for the awards granted during the periods presented:

	March 2025	May 2025	March 2024	September 2024	March 2023	July 2023
Grant-date fair value	$ 222.34	$ 167.75	$ 341.38	$ 337.23	$ 259.52	$ 222.09
Risk-free rate	3.99 %	4.00 %	4.38 %	3.54 %	4.64 %	4.70 %
Company volatility	34.60 %	33.30 %	41.40 %	34.40 %	46.90 %	47.20 %

The following table presents the Company's performance restricted stock unit activity under the Equity Plan for the year ended December 31, 2025:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2024	278,902	$ 278.72
Granted	314,724	$ 129.19
Vested	(263,000)	$ 130.23
Forfeited	(2,695)	$ 254.31
Unvested at December 31, 2025[(1)]	327,931	$ 254.50

(1) A maximum of 780,276 units could be awarded based upon the Company's final TSR ranking.

As of December 31, 2025, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $43 million, which is expected to be recognized over a weighted-average period of 1.7 years.

11. 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 and certain other subsidiaries classified as partnerships for U.S. federal income tax purposes, file a U.S. federal corporate income tax return on a consolidated basis. Viper'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 17.4%, 17.8% and 21.5% for the years ended December 31, 2025, 2024 and 2023, respectively. Total income tax expense for the year ended December 31, 2025 differed from amounts computed by applying the U.S. federal statutory tax rate to pre-tax income primarily due to (i) state income taxes, net of federal benefit, (ii) the effect of research and development tax credits, and (iii) other permanent differences between book and taxable income. Total income tax expense for the year ended December 31, 2024 differed from amounts computed by applying the U.S. federal statutory tax rate to pre-tax income primarily due to (i) the impact of removing the valuation allowance against Viper's deferred tax assets, (ii) state income taxes, net of federal benefit, and (iii) other permanent differences between book and taxable income. Total income tax expense for the year ended December 31, 2023 differed from amounts computed by applying the U.S. federal statutory tax rate to pre-tax income for the period primarily due to state income taxes, net of federal benefit, partially offset by the impact of permanent differences between book and taxable income and tax benefit resulting from a reduction in the valuation allowance on Viper's deferred tax assets.

Based on application of the Inflation Reduction Act of 2022 and related administrative guidance, the Company's income tax expense for the years ended December 31, 2025, 2024 and 2023, was not impacted by the corporate alternative minimum tax.

On July 4, 2025, the One Big Beautiful Bill Act (the "OBBB"), was enacted. The OBBB included multiple provisions applicable to U.S. income taxes for businesses, including immediate expensing of research or experimental expenses, bonus depreciation for qualified tangible property, deductible intangible drilling costs for purposes of the corporate alternative minimum tax, and enhancements to limits on business interest expense deductions. The Company accounted for the OBBB in the period of enactment and materially reduced its estimate of current tax expense for 2025, primarily offset by an increase in estimated deferred tax expense for 2025, with no material net impact on the effective tax rate for the year ended December 31, 2025.

In connection with Viper's Sitio Acquisition, Viper acquired prepaid income tax balances of approximately $14 million and deferred tax assets of $5 million related to loss carryforwards. Viper also recognized a deferred tax liability of approximately $122 million.

In connection with the 2025 Drop Down, the Company recorded a $170 million increase in tax payable and a $164 million decrease in deferred tax liability through paid in capital. Due to the resulting increase in the Company's ownership of Viper LLC, the Company recorded a $202 million decrease to deferred tax liability, and a $212 million decrease in the deferred tax asset through non-controlling interest on the Company's consolidated balance sheet.

In connection with the closing of the Endeavor Acquisition, the Company recognized a $7.2 billion deferred tax liability.

The components of the Company's consolidated provision for income taxes from continuing operations for the years ended December 31, 2025, 2024 and 2023 are as follows:

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Current income tax provision (benefit):			
Federal	$ 820	$ 752	$ 505
State	26	33	29
Total current income tax provision (benefit)	846	785	534
Deferred income tax provision (benefit):			
Federal	(486)	10	370
State	(33)	5	8
Total deferred income tax provision (benefit)	(519)	15	378
Total provision for (benefit from) income taxes	$ 327	$ 800	$ 912

A reconciliation of the statutory federal income tax amount from continuing operations to the recorded expense is as follows:

	Year Ended December 31,					
	2025		2024		2023	
	Amount (In millions)	Percentage of Income (Loss) Before Taxes	Amount (In millions)	Percentage of Income (Loss) Before Taxes	Amount (In millions)	Percentage of Income (Loss) Before Taxes
Income tax expense (benefit) at the federal statutory rate	$ 393	21%	$ 945	21%	$ 892	21%
State income tax, net of federal income tax effect[(1)]	(14)	(1)	30	1	31	1
Tax Credits:						
Research and development tax credits	(58)	(3)	(34)	(1)	—	—
Other	(2)	—	—	—	—	—
Changes in valuation allowances	—	—	(156)	(3)	(7)	(1)
Nontaxable or nondeductible items:						
Impact of nontaxable noncontrolling interest	10	—	(1)	—	—	—
Other	(2)	—	16	—	(2)	—
Changes in unrecognized tax benefits	—	—	—	—	(2)	—
Other, net	—	—	—	—	—	—
Provision for (benefit from) income taxes	$ 327	17%	$ 800	18%	$ 912	21%

(1) State taxes in Texas made up the majority of the tax effect in this category.

The components of the Company's deferred tax assets and liabilities as of December 31, 2025 and 2024 are as follows:

	December 31,	
	2025	2024
	(In millions)	
Deferred tax assets:		
Net operating loss and other carryforwards	$ 209	$ 225
Viper's investment in Viper LLC	28	185
Other	109	75
Deferred tax assets	346	485
Valuation allowance	(119)	(119)
Deferred tax assets, net of valuation allowance	227	366
Deferred tax liabilities:		
Oil and natural gas properties, midstream investments and equipment	9,286	9,990
Other	60	29
Total deferred tax liabilities	9,346	10,019
Net deferred tax liabilities	$ 9,119	$ 9,653

At December 31, 2025, the Company had approximately $245 million of federal net operating losses ("NOL") and $4 million of federal tax credits expiring in 2037, $26 million federal capital loss carryforwards expiring principally in 2027 and an additional $191 million of federal NOLs with an indefinite carryforward life, which amounts include NOLs and credit carryforwards acquired from QEP. 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, including those acquired from QEP, Rattler and Sitio, are subject to an annual limitation under Sections 382 and 383 of the Internal Revenue

Code of 1986, as amended (the “Code”), which relates to tax attribute limitations upon the 50% or greater change of ownership of an entity during any three-year look back period. Other than as described below regarding realization of tax attributes acquired from QEP, the Company believes that the application of Sections 382 and 383 of the Code will not have an adverse effect on future usage of the Company’s loss carryforwards and credits.

As of December 31, 2025, the Company had a valuation allowance of $11 million related to federal NOL and credit carryforwards acquired from QEP which the Company estimated have a remote likelihood of being realized prior to expiration. In addition, the Company had a valuation allowance of $108 million primarily related to certain state NOL carryforwards which the Company does not believe are realizable as it does not anticipate significant future operations in those states. 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 and the limitations imposed by Sections 382 and 383 of the Code on certain of the Company’s NOLs and other carryforwards. Management believes that the balance of the Company’s NOLs is realizable, to the extent of future taxable income, due to an increase in our Section 382 limitations as a result of our fair market value and our net unrealized built-in gain position. As of December 31, 2025, management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

At December 31, 2025, the Company’s net deferred tax liabilities include deferred tax assets of approximately $28 million related to Viper’s investment in Viper LLC. Deferred taxes are provided on the difference between Viper’s basis for financial accounting purposes and basis for federal income tax purposes in its investment in Viper LLC.

During the year ended December 31, 2024, Viper released its remaining valuation allowance of approximately $156 million as a result of management’s assessment of the realizability of future taxable income. During the year ended December 31, 2023, Viper recognized deferred income tax benefit of $7 million related to a partial release in its beginning-of-the year valuation allowance, based on a change in judgment about the realizability of its deferred tax assets.

The following table sets forth changes in the Company’s unrecognized tax benefits:

	December 31,		
	2025	2024	2023
	(In millions)		
Balance at beginning of year	$ —	$ —	$ 7
Decrease resulting from expiration of statute	—	—	(7)
Balance at end of year	—	—	—
Less: Effects of temporary items	—	—	—
Total that, if recognized, would impact the effective income tax rate as of the end of the year	$ —	$ —	$ —

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. The Company’s federal and state income tax returns for the years ended December 31, 2022 through December 31, 2024 remain open for all purposes of examination by the Internal Revenue Service and major state taxing jurisdictions. However, certain earlier tax years remain open for adjustment to the extent of their NOL carryforwards available for future utilization. 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.

The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December 31, 2025 and 2024, there was no interest associated with uncertain tax positions recognized in the Company’s consolidated financial statements. During the year ended December 31, 2023, there was an insignificant amount of interest associated with uncertain tax positions recognized in the Company’s consolidated financial statements. During the years ended December 31, 2025, 2024 and 2023, there were no penalties related to each period associated with uncertain tax positions recognized in the Company’s consolidated financial statements.

12. DERIVATIVES

At December 31, 2025, the Company has commodity derivative contracts and interest rate swaps outstanding. All derivative financial instruments are recorded at fair value.

Commodity Contracts

The Company has entered into multiple crude oil and natural gas 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. The Company has not designated its commodity derivative instruments as hedges for accounting purposes and, as a result, marks its commodity 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.”

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 has entered into commodity derivative instruments only with counterparties that are also lenders under its credit facility and have been deemed an acceptable credit risk. As such, collateral is not required from either the counterparties or the Company on its outstanding commodity derivative contracts.

As of December 31, 2025, the Company had the following outstanding commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed:

					Swaps	Collars	
Settlement Month	Settlement Year	Type of Contract	Bbls/MMBtu Per Day	Index	Weighted Average Differential	Weighted Average Floor Price	Weighted Average Ceiling Price
OIL							
Jan. - Jun.	2026	Basis Swap[(1)]	35,000	Argus WTI Midland	$0.94	$—	$—
Jul. - Dec.	2026	Basis Swap[(1)]	30,000	Argus WTI Midland	$0.93	$—	$—
NATURAL GAS							
Jan. - Dec.	2026	Costless Collar	840,000	Henry Hub	$—	$2.87	$6.35
Jan. - Dec.	2027	Costless Collar	640,000	Henry Hub	$—	$2.90	$6.41
Jan. - Dec.	2026	Basis Swap[(1)]	650,000	Waha Hub	$(1.69)	$—	$—
Jan. - Dec.	2026	Basis Swap[(1)]	100,000	HSC Hub	$(0.35)	$—	$—
Jan. - Dec.	2027	Basis Swap[(1)]	340,000	Waha Hub	$(1.28)	$—	$—
Jan. - Dec.	2027	Basis Swap[(1)]	180,000	HSC Hub	$(0.25)	$—	$—

(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, the Waha Hub and the HSC Hub natural gas price. The weighted average differential represents the amount of reduction to the Cushing, Oklahoma, oil price and the Waha Hub and HSC Hub natural gas price for the notional volumes covered by the basis swap contracts.

Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Strike Price	Deferred Premium
OIL						
Jan. - Mar.	2026	Put	36,000	Brent	$53.13	$1.73
Jan. - Mar.	2026	Put	95,000	Argus WTI Houston	$51.13	$1.66
Jan. - Mar.	2026	Put	185,000	WTI Cushing	$51.73	$1.64
Apr. - Jun.	2026	Put	27,000	Brent	$52.50	$1.72
Apr. - Jun.	2026	Put	70,000	Argus WTI Houston	$50.00	$1.68
Apr. - Jun.	2026	Put	130,000	WTI Cushing	$49.71	$1.70
Jul. - Sep.	2026	Put	5,000	Brent	$52.50	$1.63
Jul. - Sep.	2026	Put	15,000	Argus WTI Houston	$50.00	$1.74
Jul. - Sep.	2026	Put	20,000	WTI Cushing	$50.00	$1.84

Interest Rate Swaps and Treasury Locks

Interest Rate Swaps

As of December 31, 2025, the Company has two receive-fixed, pay-variable interest rate swap agreements for notional amounts of $150 million each, which are considered economic hedges of the Company’s 2029 Notes. During the year ended December 31, 2025, the Company terminated and settled an aggregate $600 million of the previous $900 million of the notional amount of interest rate swaps for a loss of $67 million. During the year ended December 31, 2024, the Company terminated and settled an aggregate $300 million of the previous $1.2 billion of the notional amount of interest rate swaps for a loss of $37 million. The losses on the partial termination of interest rate swaps are recognized in the caption “Gain (loss) on derivative instruments, net” on the consolidated statement of operations for the years ended December 31, 2025 and 2024. The Company receives a fixed 3.50% rate of interest on these swaps and pays the variable rate of SOFR plus 2.1865%. The interest rate swaps are not treated as hedges for accounting purposes and, as a result, changes in fair value are recorded in earnings under the caption “Gain (loss) on derivative instruments, net” in the consolidated statements of operations.

The interest rate swaps were designated as fair value hedges at inception, but the Company subsequently elected to discontinue hedge accounting. The cumulative fair value basis adjustment recorded at the time of dedesignation is being amortized to interest expense over the remaining term of the 2029 Notes utilizing the effective interest method. See Note 8—Debt for further details.

Treasury Locks

From time to time the Company enters into certain treasury lock contracts to reduce the forecasted interest rate risk associated with the issuance of senior unsecured notes. Changes in the value and settlement of treasury locks are recognized under the caption “Gain (loss) on derivative instruments, net” on the consolidated statement of operations.

Balance Sheet Offsetting of Derivative Assets and Liabilities

The fair value of derivative instruments 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 13—Fair Value Measurements for further details.

Gains and Losses on Derivative Instruments

The following table summarizes the gains and losses on derivative instruments included in the consolidated statements of operations:

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Gain (loss) on derivative instruments, net:			
Commodity contracts	$ 311	$ 210	$ (239)
Interest rate swaps[1]	18	(45)	(20)
2026 WTI Contingent Liability	10	(3)	—
Treasury locks	2	(25)	—
Total	$ 341	$ 137	$ (259)
Net cash received (paid) on settlements:			
Commodity contracts	$ 259	$ 57	$ (61)
Interest rate swaps[1]	(80)	(83)	(49)
Treasury locks	2	(25)	—
Total	$ 181	$ (51)	$ (110)

(1) The years ended December 31, 2025 and 2024 include cash paid on interest rate swaps terminated prior to their contractual maturity of $67 million and $37 million, respectively.

13. 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.

See Note 4—Acquisitions and Divestitures for discussion of the fair values of proved oil and natural gas properties assumed in business combinations.

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 commodity derivative instruments, interest rate swaps and investments in the common stock of other entities. The fair values of the Company's commodity 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. The fair values of the Company's interest rate swaps are determined based on inputs that are readily available in public markets, are determined based on inputs readily available in public markets, can be derived from information available in publicly quoted markets, or are provided by financial institutions that trade these contracts. These valuations are Level 2 inputs. The fair values of the Company's commodity derivative instruments and interest rate swaps are recorded as assets or liabilities on the consolidated balance sheets. The net amounts of derivative instruments are classified as current or noncurrent based on their anticipated settlement dates.

The Company has an immaterial investment in the Class A common stock of Verde Clean Fuels, Inc. The Company elected the fair value option for measuring the fair value of this equity investment. The investment is reported at fair value using observable, quoted stock prices and is included in "Other assets" on the Company's consolidated balance sheets at December 31, 2025 and 2024.

Viper LLC's 2026 WTI Contingent Liability is reported at fair value using observable market data inputs and a Monte Carlo pricing model, which are considered Level 2 inputs within the fair value hierarchy. The 2026 WTI Contingent Liability was recorded in "Other accrued liabilities" on the Company's consolidated balance sheet at December 31, 2025, and in "Other long-term liabilities" on the Company's consolidated balance sheet at December 31, 2024. The change in fair value of the 2026 WTI Contingent Liability is recognized in "Gain (loss) on derivative instruments, net" on the Company's consolidated statements of operations for the year ended December 31, 2025.

The following tables provide (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. The net amounts are presented under the captions (i) "Prepaid expenses and other current assets," (ii) "Other assets," (iii) "Derivative instruments," and (iv) "Other long-term liabilities" in the Company's consolidated balance sheets as of December 31, 2025 and December 31, 2024:

	As of December 31, 2025					
Balance Sheet Classification	**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:						
Prepaid expenses and other current assets:						
Commodity derivative instruments	$ —	$ 335	$ —	$ 335	$ (101)	$ 234
Other assets:						
Commodity derivative instruments	$ —	$ 49	$ —	$ 49	$ (42)	$ 7
Investment	$ 30	$ —	$ —	$ 30	$ —	$ 30
Liabilities:						
Derivative instruments:						
Commodity derivative instruments	$ —	$ 109	$ —	$ 109	$ (101)	$ 8
Interest rate swaps	$ —	$ 7	$ —	$ 7	$ —	$ 7
Other accrued liabilities:						
2026 WTI Contingent Liability	$ —	$ 20	$ —	$ 20	$ —	$ 20
Other long-term liabilities:						
Commodity derivative instruments	$ —	$ 77	$ —	$ 77	$ (42)	$ 35
Interest rate swaps	$ —	$ 20	$ —	$ 20	$ —	$ 20

Balance Sheet Classification	As of December 31, 2024 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:						
Prepaid expenses and other current assets:						
Commodity derivative instruments	$ —	$ 274	$ —	$ 274	$ (106)	$ 168
Other assets:						
Commodity derivative instruments	$ —	$ 19	$ —	$ 19	$ (17)	$ 2
Investment	$ 8	$ —	$ —	$ 8	$ —	$ 8
Liabilities:						
Derivative instruments:						
Commodity derivative instruments	$ —	$ 121	$ —	$ 121	$ (106)	$ 15
Interest rate swaps	$ —	$ 28	$ —	$ 28	$ —	$ 28
Other long-term liabilities:						
Commodity derivative instruments	$ —	$ 27	$ —	$ 27	$ (17)	$ 10
Interest rate swaps	$ —	$ 96	$ —	$ 96	$ —	$ 96
2026 WTI Contingent Liability	$ —	$ 30	$ —	$ 30	$ —	$ 30

Assets and Liabilities Not Recorded at Fair Value

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

	December 31, 2025		December 31, 2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Debt	$ 14,489	$ 14,497	$ 12,975	$ 12,564

The fair values of the Company's borrowings under the Credit Agreement, the Viper Revolving Credit Facility, the 2025 Term Loan, Viper 2025 Term Loan and Tranche A Loans (prior to repayment and termination) approximate their carrying values based on borrowing rates available to the Company for bank loans with similar terms and maturities and are classified as Level 2 in the fair value hierarchy. The fair values of the outstanding notes were determined using the quoted market price at each period end, a Level 1 classification in the fair value hierarchy.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in certain circumstances. These assets and liabilities can include those acquired in a business combination, inventory, proved and unproved oil and natural gas properties, equity method investments, asset retirement obligations and other long-lived assets that are written down to fair value when impaired or held for sale. Refer to Note 4—Acquisitions and Divestitures and Note 5—Property and Equipment for additional discussion of nonrecurring fair value adjustments.

Fair Value of Financial Assets

The carrying amount of cash and cash equivalents, accounts receivable, prepaid expenses and other current assets, funds held in escrow, accounts payable and other accrued liabilities approximate their fair value because of the short-term nature of the instruments.

14. SUPPLEMENTAL INFORMATION TO STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ (155)	$ (269)	$ (146)
Cash paid for income taxes, net of refunds:			
Federal	$ (1,178)	$ (575)	$ (316)
State:			
Texas	$ (54)	$ (31)	$ (34)
Other	$ (2)	$ 1	$ (2)
Supplemental disclosure of non-cash transactions:			
Accrued capital expenditures included in accounts payable and accrued expenses	$ 966	$ 787	$ 618
Capitalized stock-based compensation	$ (33)	$ (30)	$ (26)
Common shares issued for acquisitions	$ (1,116)	$ (20,110)	$ (633)
Viper common stock issued for acquisition	$ (1,435)	$ —	$ (255)
Viper LLC units issued for acquisition	$ (1,445)	$ (468)	$ —
Assets contributed in exchange for ownership interest in an equity method investment	$ (34)	$ —	$ (126)
Asset retirement obligations acquired	$ (15)	$ (278)	$ (8)

Non-cash investing activities for the year ended December 31, 2024 include additions of $1.0 billion as a result of the TRP Exchange. See Note 4—Acquisitions and Divestitures for further discussion of the TRP Exchange.

15. COMMITMENTS AND CONTINGENCIES

The Company is a party to various routine legal proceedings, disputes and claims arising in the ordinary 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, personal injury claims, title disputes, royalty disputes, contract claims, employment claims, claims alleging violations of antitrust laws, 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 the Company's current operations. 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 accrued liabilities 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 noncancellable terms in excess of one year as of December 31, 2025:

Year Ending December 31,	Transportation Commitments(1)(2)	Electrical Power Agreements(3)	Other Operating Agreements(4)	Electrical Fracturing Fleet(5)
	(In millions)			
2026	$ 275	$ 125	$ 114	$ 50
2027	316	128	43	50
2028	313	98	14	24
2029	312	95	6	—
2030	312	21	6	—
Thereafter	1,485	28	24	—
Total	$ 3,013	$ 495	$ 207	$ 124

(1) Total costs incurred under take-or-pay and throughput obligations were approximately $449 million, $337 million and $266 million in 2025, 2024 and 2023, respectively.
(2) The Company has committed to transport gross quantities of crude oil and natural gas 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.
(3) The Company has fixed price contracts with various suppliers for the purchase of electrical power through 2032.
(4) The Company is party to various operational agreements containing fixed or minimum payments, which include the rental of compressors, sand purchases, produced water disposal and miscellaneous other operating leases. The amounts in the table above represent our fixed or minimum payments under the aforementioned types of agreements.
(5) The Company has commitments for the Company's electric fracturing fleet and related power generating services.

At December 31, 2025, the Company's delivery commitments covered the following gross volumes of oil:

Year Ending December 31,	Oil Volume Commitments (Bbl/d)
2026	150,000
2027	150,000
2028	50,000
2029	50,000
2030	50,000
Thereafter	50,000
Total	500,000

The Company and Five Point currently anticipate collectively contributing $500 million in follow-on capital to fund future growth projects and acquisitions for Deep Blue.

Environmental Matters

The United States Department of the Interior, Bureau of Safety and Environmental Enforcement ordered several oil and gas operators, including a corporate predecessor of Energen Corporation, to perform decommissioning and reclamation activities related to a Louisiana offshore oil and gas production platform and related facilities. In response to the insolvency of the operator of record, the government ordered the former operators and/or alleged former lease record title owners to decommission the platform and related facilities. The Company has agreed to an arrangement with other operators to contribute to a trust to fund the decommissioning costs, however, the Company's portion of such costs are not expected to be material.

Several coastal Louisiana parishes and the State of Louisiana have filed numerous lawsuits under Louisiana's State and Local Coastal Resources Management Act ("SLCRMA") against numerous oil and gas producers seeking damages for coastal erosion in or near oil fields located within Louisiana's coastal zone. The Company is a defendant in five of these cases. The Company has exercised contractual indemnification rights where applicable. Plaintiffs' SLCRMA theories are unprecedented and there remains significant uncertainty about the claims (both as to scope and damages). Although the Company cannot predict the ultimate outcome of these matters, the Company believes the claims lack merit and intends to continue vigorously defending these lawsuits.

16. SUBSEQUENT EVENTS

Fourth Quarter 2025 Dividend Declaration

On February 19, 2026, the board of directors of the Company approved an increase in the Company's annual base dividend to $4.20 per share of common stock and declared a base cash dividend for the fourth quarter of 2025 of $1.05 per share of common stock, payable on March 12, 2026 to its stockholders of record at the close of business on March 5, 2026. Future base and variable dividends are at the discretion of the Company's board of directors.

Viper Divestiture of Non-Permian Assets

On February 9, 2026, Viper divested all of its non-Permian assets, including those acquired from Sitio, to an affiliate of GRP Energy Capital LLC and Warwick Capital Partners LLP for net cash proceeds of approximately $617 million, subject to customary post-closing adjustments. The divested properties consisted of approximately 9,400 net royalty acres in the Denver-Julesburg, Eagle Ford and Williston basins with current production of approximately 4,750 BO/d. Proceeds from the divestiture were used to repay (i) the Viper 2025 Term Loan of $500 million in full, (ii) repay the outstanding borrowings under the Viper Revolving Credit Facility, and (iii) for general corporate purposes.

Interest Rate Swaps

During the first quarter of 2026, the Company fully terminated and settled the remaining aggregate $300 million of notional interest rate swaps for approximately $27 million in cash.

SGF Common Stock Repurchases

Pursuant to a letter agreement executed with SGF in the fourth quarter of 2025, the Company repurchased 2.0 million shares from SGF for approximately $332 million, excluding excise tax, during the first quarter of 2026. For further details on the nature of transactions with SGF, see Note 7—Related Party Transactions.

17. SEGMENT INFORMATION

The Company is managed on a consolidated basis as one operating segment and one reportable segment: 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. This singular operating and reportable segment is comprised of (i) the Company and its wholly-owned subsidiaries, and (ii) Viper and its consolidated subsidiaries, which have been aggregated due to the similarity in their economic characteristics, products and services, processes, type of customers, method of distribution for their products and the regulatory environment in which they operate. The upstream segment derives its revenue from customers through the sale of oil and natural gas products as well as other immaterial service contracts. See Note 3—Revenue from Contracts with Customers for further discussion of the Company's sources of revenue.

The Company's Chief Operating Decision Maker ("CODM") is a senior executive committee that is comprised of the Chief Operating Officer, Chief Financial Officer, and Chief Executive Officer. The CODM uses the Company's consolidated financial results to make key operating decisions, assess performance and to allocate resources. The measures of segment profit or loss and total assets utilized by the CODM are net income and total assets as reported on the consolidated statements of operations and the consolidated balance sheets, respectively. The significant expense categories, their amounts and other segment items that are regularly provided to the CODM are those that are reported in the Company's consolidated statements of operations as well as interest income and interest expense in Note 8—Debt.

The CODM uses consolidated net income as a measure of profitability to evaluate segment performance and to make capital allocation decisions such as reinvestment in the business or return of capital through the payment of base and variable dividends or repurchases under the share repurchase program.

18. 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,	
	2025	2024
	(In millions)	
Oil and natural gas properties:		
Proved properties	$ 71,588	$ 59,574
Unproved properties	23,941	22,666
Total oil and natural gas properties	95,529	82,240
Accumulated depletion	(15,974)	(11,083)
Accumulated impairment	(11,606)	(7,954)
Net oil and natural gas properties capitalized	$ 67,949	$ 63,203

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,		
	2025	2024	2023
	(In millions)		
Acquisition costs:			
Proved properties	$ 4,608	$ 21,275	$ 1,314
Unproved properties	5,226	15,568	1,701
Development costs	3,613	2,992	1,962
Exploration costs	212	194	768
Total	$ 13,659	$ 40,029	$ 5,745

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil, natural gas and natural gas liquids. It does not include any interest costs or general and administrative costs. Income tax expense has been calculated by applying statutory income tax rates to oil, gas and natural gas liquids sales after deducting production costs, depreciation, depletion and amortization and accretion and impairment. Therefore, the following schedule is not necessarily indicative of the contribution to the net operating results of the Company's oil, natural gas and natural gas liquids operations.

	Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Oil, natural gas and natural gas liquid sales	$ 13,453	$ 10,100	$ 8,228
Production costs	(3,231)	(2,280)	(1,684)
Depreciation, depletion, amortization and accretion	(4,943)	(2,781)	(1,684)
Impairment	(3,652)	—	—
Income tax benefit (expense)	(362)	(1,025)	(1,000)
Results of operations	$ 1,265	$ 4,014	$ 3,860

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates and their associated future net cash flows were prepared by the Company's internal reservoir engineers and audited by Ryder Scott, independent petroleum engineers, as of December 31, 2025, 2024 and 2023. 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 SEC Prices for the periods ending December 31, 2025, 2024 and 2023, respectively. 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 the net revenue interest in the Company's properties, all of which are located within the continental United States. Although the Company believes 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.

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 following table presents changes in the Company's estimated proved reserves (including those attributable to Viper). As of December 31, 2025, none of the Company's total proved reserves were classified as proved developed non-producing.

	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBOE)[(1)]
Proved Developed and Undeveloped Reserves:				
As of December 31, 2022	1,069,508	2,868,861	485,319	2,032,971
Extensions and discoveries	206,562	424,881	78,498	355,874
Revisions of previous estimates	(56,482)	(47,697)	9,962	(54,470)
Purchase of reserves in place	41,790	79,507	15,440	70,481
Divestitures	(21,258)	(130,013)	(20,755)	(63,682)
Production	(96,176)	(198,117)	(34,217)	(163,413)
As of December 31, 2023	1,143,944	2,997,422	534,247	2,177,761
Extensions and discoveries	168,375	310,421	58,696	278,808
Revisions of previous estimates	(78,142)	(158,468)	(24,518)	(129,071)
Purchase of reserves in place	697,702	2,391,264	473,236	1,569,482
Divestitures	(47,505)	(240,044)	(33,080)	(120,592)
Production	(123,325)	(275,680)	(49,700)	(218,972)
As of December 31, 2024	1,761,049	5,024,915	958,881	3,557,416
Extensions and discoveries	306,431	765,623	144,884	578,919
Revisions of previous estimates	(173,561)	(253,282)	(88,310)	(304,085)
Purchase of reserves in place	99,239	268,935	44,547	188,609
Divestitures	(37,276)	(84,515)	(15,463)	(66,825)
Production	(181,462)	(447,855)	(80,073)	(336,178)
As of December 31, 2025	1,774,420	5,273,821	964,466	3,617,856
Proved Developed Reserves:				
December 31, 2022	699,513	2,122,782	350,243	1,403,553
December 31, 2023	744,103	2,203,563	385,167	1,496,530
December 31, 2024	1,120,824	3,559,748	670,683	2,384,798
December 31, 2025	1,173,636	3,872,360	701,999	2,521,028
Proved Undeveloped Reserves:				
December 31, 2022	369,995	746,079	135,076	629,418
December 31, 2023	399,841	793,859	149,080	681,231
December 31, 2024	640,225	1,465,167	288,198	1,172,618
December 31, 2025	600,784	1,401,461	262,467	1,096,828

(1) Includes total proved reserves of 231,440 MBOE, 107,730 MBOE, 78,870 MBOE and 65,516 MBOE as of December 31, 2025, 2024, 2023 and 2022, respectively, attributable to the non-controlling interest in Viper.

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, 2025, the Company's extensions and discoveries of 578,919 MBOE resulted primarily from the drilling of 1,571 new wells in which the Company has an interest, including 1,311 wells in which the Company owns only a mineral interest through Viper, and from 582 new proved undeveloped locations added. Viper royalty interests accounted for 11% of the extension volumes. The Company's downward revisions of previous estimates of 304,085 MBOE were primarily attributable to negative revisions of (i) 130,101 MBOE associated with lower commodity prices, (ii) 128,883 MBOE primarily due to downgrades related to changes in the corporate development plan, and (iii) 45,101 MBOE primarily attributable to performance revisions. Purchases of 188,609 MBOE consisted of 90,340 MBOE attributable largely to the Double Eagle Acquisition and 98,269 MBOE of Viper royalty purchases attributable largely to Viper's Sitio Acquisition. Divestitures of 66,825 MBOE related primarily to non-core Delaware Basin assets.

During the year ended December 31, 2024, the Company's extensions and discoveries of 278,808 MBOE resulted primarily from the drilling of 1,172 new wells in which the Company has an interest, including 862 wells in which the Company owns only a mineral interest through Viper, and from 445 new proved undeveloped locations added. Viper royalty interests accounted for 9% of the extension volumes. The Company's downward revisions of previous estimates of 129,071 MBOE were primarily attributable to negative revisions of (i) 88,915 MBOE associated with lower commodity prices, (ii) 49,311 MBOE due to downgrades related to changes in the corporate development plan, and (iii) 16,586 MBOE due to a decline in performance. These were partially offset by positive revisions of 25,743 MBOE due to positive ownership and acquisition variance revisions. Purchases of 1,569,482 MBOE consisted of 1,554,541 MBOE attributable largely to the Endeavor Acquisition and 14,941 MBOE of Viper royalty purchases. Divestitures of 120,592 MBOE related primarily to non-core Midland Basin assets.

During the year ended December 31, 2023, the Company's extensions and discoveries of 355,874 MBOE resulted primarily from the drilling of 954 new wells in which the Company has an interest, including 826 wells in which the Company owns only a mineral interest through Viper, and from 344 new proved undeveloped locations added. Viper royalty interests accounted for 7% of the extension volumes. The Company's downward revisions of previous estimates of 54,470 MBOE were primarily attributable to negative revisions of (i) 62,370 MBOE associated with lower commodity prices, and (ii) 32,249 MBOE due to PUD downgrades related to changes in the corporate development plan. These were partially offset by positive revisions of 40,149 MBOE due to improved performance. Purchases of 70,481 MBOE consisted of 54,470 MBOE attributable largely to the Lario Acquisition and 16,011 MBOE of Viper royalty purchases. Divestitures of 63,682 MBOE related primarily to non-core Midland Basin assets.

Proved Undeveloped Reserves (PUDs)

At December 31, 2025, the Company's estimated PUD reserves were approximately 1,096,828 MBOE, a 75,790 MBOE decrease over the reserve estimate at December 31, 2024 of 1,172,618 MBOE. The following table includes the changes in PUD reserves for 2025 (MBOE):

Beginning proved undeveloped reserves at December 31, 2024	1,172,618
Undeveloped reserves transferred to developed	(360,141)
Revisions	(170,400)
Purchases	25,331
Divestitures	(44,437)
Extensions and discoveries	473,857
Ending proved undeveloped reserves at December 31, 2025	1,096,828

The decrease in proved undeveloped reserves was primarily attributable to (i) transfers of 360,141 MBOE from undeveloped to developed reserves as a result of drilling or participating in 408 gross (377 net) horizontal wells in which the Company has a working interest and 247 gross wells in which the Company also has a royalty interest or mineral interest through Viper, and (ii) downward revisions of 170,400 MBOE, which were primarily the result of negative revisions of 122,117 MBOE due to downgrades related to changes in the corporate development plan, and negative revisions of 48,283 MBOE primarily attributable to performance revisions. Divestitures of 44,437 MBOE related primarily to non-core Delaware Basin assets and trades in the Midland Basin. The decrease in proved undeveloped reserves was partially offset by extensions of 427,437 MBOE from 582 gross (537 net) wells in which the Company has a working interest and 46,420 MBOE from 1,071 gross wells in which Viper owns royalty interests. All gross working interest wells were in the Midland Basin. Purchases of 25,331 MBOE were primarily attributable to individually insignificant trades and asset acquisitions.

During 2025, approximately $3.6 billion 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. Estimated future development costs relating to the development of PUDs are projected to be approximately $2.3 billion in 2026, $2.6 billion in 2027, $1.8 billion in 2028, $839 million in 2029 and $175 million in 2030. 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.

With our current development plan, we expect to continue our strong PUD conversion ratio in 2026 by converting an estimated 38% of our PUDs to a proved developed category and developing approximately 89% of the consolidated 2025 year-end PUD reserves by the end of 2028. As of December 31, 2025, all of our proved undeveloped reserves are scheduled to be developed within five years from the date they were initially recorded.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is based on the unweighted arithmetic average, first-day-of-the-month price for the rolling 12-month period. 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, 2025, 2024 and 2023:

	December 31,		
	2025	2024	2023
	(In millions)		
Future cash inflows	$ 140,499	$ 157,944	$ 106,418
Future development costs[1]	(9,425)	(9,992)	(6,400)
Future production costs	(40,789)	(44,097)	(25,656)
Future production taxes	(9,870)	(10,975)	(7,434)
Future income tax expenses	(12,129)	(16,115)	(11,067)
Future net cash flows	68,286	76,765	55,861
10% discount to reflect timing of cash flows	(31,376)	(36,932)	(28,803)
Standardized measure of discounted future net cash flows[2]	$ 36,910	$ 39,833	$ 27,058

(1) Includes approximately $1.1 billion, $1.3 billion and $685 million of undiscounted future asset retirement costs for the years ended December 31, 2025, 2024 and 2023, respectively, based on estimates made at the end of each of the respective years.
(2) Includes $6.6 billion, $3.3 billion and $3.2 billion, for the years ended December 31, 2025, 2024 and 2023, respectively, attributable to the Company’s consolidated subsidiary, Viper, in which there is a 57%, 55% and 44% non-controlling interest at December 31, 2025, 2024 and 2023, respectively.

The table below presents the SEC Prices as adjusted for differentials and contractual arrangements utilized in the computation of future cash inflows:

	December 31,		
	2025	2024	2023
Oil (per Bbl)	$ 64.99	$ 76.15	$ 77.62
Natural gas (per Mcf)	$ 1.32	$ 0.54	$ 1.53
Natural gas liquids (per Bbl)	$ 18.87	$ 22.02	$ 24.40

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,		
	2025	2024	2023
	(In millions)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 39,833	$ 27,058	$ 35,699
Sales of oil and natural gas, net of production costs	(10,222)	(7,820)	(6,544)
Acquisitions of reserves	3,630	21,639	1,854
Divestitures of reserves	(632)	(1,318)	(938)
Extensions and discoveries, net of future development costs	7,496	4,124	5,771
Previously estimated development costs incurred during the period	1,920	1,447	1,180
Net changes in prices and production costs	(8,117)	(4,969)	(17,276)
Changes in estimated future development costs	1,084	1,066	518
Revisions of previous quantity estimates	(4,191)	(2,035)	(1,268)
Accretion of discount	4,849	3,921	4,533
Net change in income taxes	1,702	(3,156)	2,506
Net changes in timing of production and other	(442)	(124)	1,023
Standardized measure of discounted future net cash flows at the end of the period	$ 36,910	$ 39,833	$ 27,058

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls 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 include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. 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, 2025, 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 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, 2025, our disclosure controls and procedures are effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. Viper is in the process of integrating the entities acquired in the Sitio Acquisition. As a result of these integration activities, certain controls will be evaluated and may be changed. Except as noted above, there have not been any changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control 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, 2025. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in Viper's Sitio Acquisition on August 19, 2025. The total assets of Sitio represent approximately 6% of our consolidated total assets as of December 31, 2025, and the revenues of Sitio represent 1% of our consolidated revenues for the year ended December 31, 2025.

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, 2025. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2025, 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, 2025, 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, 2025, 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, 2025, and our report dated February 25, 2026 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 ("Management's Report"). 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.

Our audit of, and opinion on, the Company's internal control over financial reporting does not include the internal control over financial reporting of the entities acquired in the Sitio Acquisition, whose financial statements reflect total assets and revenues constituting 6 and 1 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2025. As indicated in Management's Report, the entities acquired in the Sitio Acquisition were acquired during 2025. Management's assertion on the effectiveness of the Company's internal control over financial reporting excluded internal control over financial reporting of the entities acquired in the Sitio Acquisition.

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, 2026

ITEM 9B. OTHER INFORMATION

None of our directors or officers adopted or terminated a Rule 10b5-1 trading arrangement or a non-Rule 10b5-1 trading arrangement during the Company's fiscal quarter ended December 31, 2025.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

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, 2025.

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. We have also made the Code of Business Conduct and Ethics available on our website under the "Investors—Corporate Governance" section at https://www.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, 2025.

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, 2025.

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, 2025.

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, 2025.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as a part of this Form 10-K

1 and 2. Financial Statements and Financial Statement Schedules

The financial statements filed as part of this Annual Report on Form 10-K are listed in the accompanying index to financial statements and schedules under Part II, Item 8. Financial Statements and Supplementary Data.

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 May 15, 2022, by and among Diamondback Energy, Inc., Rattler Midstream GP LLC, Bacchus Merger Sub Company and Rattler Midstream LP (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on May 16, 2022).
2.2#	Agreement and Plan of Merger, dated as of February 11, 2024, by and among the Company, Endeavor, Merger Sub I, Merger Sub II and the Company Representative (for purposes of certain sections set forth therein) (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 12, 2024).
2.3	Letter Agreement, amending the Merger Agreement, by and among the Company, Endeavor, Merger Sub I, Merger Sub II and the Company Representative, dated March 18, 2024 (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 18, 2024).
3.1	Second 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 June 14, 2023).
3.2	Certificate of Amendment No. 1 to Second 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 September 10, 2024).
3.3	Sixth Amended and Restated Bylaws of the Company, adopted as of October 31, 2025 (incorporated by reference to Exhibit 3.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 5, 2025).
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 26, 2025).
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 5, 2019, between Diamondback Energy, Inc. and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (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).
4.4	First Supplemental Indenture, dated as of December 5, 2019, among Diamondback Energy, Inc., Diamondback E&P LLC, as successor by merger to Diamondback O&G LLC, and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (including the forms of 3.250% Senior Notes due 2026 and 3.500% Senior Notes due 2029) (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).
4.5	Third Supplemental Indenture, dated as of March 24, 2021, among Diamondback Energy, Inc., Diamondback E&P LLC, as successor by merger to Diamondback O&G LLC, and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (including the forms of 3.125% Senior Notes due 2031 and 4.400% Senior Notes due 2051) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 24, 2021).
4.6	Fourth Supplemental Indenture, dated as of June 30, 2021, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 5, 2021).
4.7	Fifth Supplemental Indenture, dated as of March 17, 2022, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as trustee (including the form of 4.250% Senior Notes due 2052) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 17, 2022).
4.8	Sixth Supplemental Indenture, dated as of October 28, 2022, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association (including the form of 6.250% Senior Notes due 2033) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 28, 2022).
4.9	Amended and Restated Officers' Certificate, dated as of February 27, 1998, between Energen Corporation and The Bank of New York as trustee, relating to the Medium-Term Notes, Series B, due 2028 (incorporated by reference to Exhibit 4(d)(iii) to the Form 10-K, File No. 001-7810, filed by Energen Corporation with the SEC on February 28, 2018).

Exhibit Number	Description
4.10	Indenture, dated as of March 1, 2012, between QEP Resources, Inc. and Wells Fargo Bank, National Association as trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-34778, filed by QEP Resources, Inc. with the SEC on March 1, 2012).
4.11	First Supplemental Indenture, dated as of March 23, 2021, among QEP Resources, Inc. 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 March 24, 2021).
4.12	Indenture, dated as of December 13, 2022, between Diamondback Energy, Inc. and Computershare Trust Company, 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 13, 2022).
4.13	First Supplemental Indenture, dated as of December 13, 2022, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as trustee (including the form of 6.250% Senior Notes due 2053) (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 13, 2022).
4.14	Second Supplemental Indenture, dated as of April 18, 2024, by and among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as Trustee (including forms of 5.200% Senior Notes due 2027, 5.150% Senior Notes due 2030, 5.400% Senior Notes due 2034, 5.750% Senior Notes due 2054 and 5.900% Senior Notes due 2064) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on April 18, 2024).
4.15	Third Supplemental Indenture, dated as of March 20, 2025, between Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 20, 2025).
4.16	Indenture, dated as of July 23, 2025, between Viper Energy Partners LLC and Computershare Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-36505, filed by Former Viper with the SEC on July 23, 2025).
4.17	First Supplemental Indenture, dated as of July 23, 2025, by and among Viper Energy Partners LLC, Former Viper and Computershare Trust Company, National Association, as Trustee (including the form of the Notes) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-36505, filed by Former Viper with the SEC on July 23, 2025).
4.18	Second Supplemental Indenture, dated as of August 19, 2025, by and among Viper Energy Partners LLC, New Viper and Computershare Trust Company, National Association (incorporated by reference to Exhibit 4.8 to the Form 8-K12B, File No. 001-42807, filed by New Viper with the SEC on August 19, 2025).
4.19	Stockholders Agreement, by and among the Company and the initial stockholders named therein, dated September 10, 2024 (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on September 10, 2024).
10.1+	2021 Amended and Restated Diamondback Energy, Inc. Equity Incentive Plan (incorporated by reference to Appendix B to Schedule DEF 14A, File No. 001-35700, filed by the Company with the SEC on April 23, 2021).
10.2+	Amendment No. 1 to 2021 Amended and Restated Diamondback Energy, Inc. Equity Incentive Plan, adopted effective as of February 11, 2024 (incorporated by reference to Exhibit 10.2 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 22, 2024).
10.3+	2023 Form of Time-based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.8 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 23, 2023).
10.4+	2023 Form of Performance-based Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.9 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 23, 2023).
10.5+	2024 Form of Time-based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.9 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 22, 2024).
10.6+	2024 Form of Performance-based Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.10 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 22, 2024).
10.7+	2025 Form of Time-based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.11 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 26, 2025).
10.8+	2025 Form of Performance-based Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.12 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 26, 2025).
10.9+*#	2026 Form of Time-based Restricted Stock Unit Award Agreement.
10.10+*#	2026 Form of Performance-based Restricted Stock Unit Agreement.

Exhibit Number	Description
10.11+	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).
10.12+	Diamondback Energy, Inc. Amended and Restated Senior Management Severance Plan, adopted effective as of April 6, 2025 (including a form of participation agreement attached thereto as Schedule C) (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on May 7, 2025).
10.13+	Form of Participation Agreement (incorporated by reference from Schedule C to Diamondback Energy, Inc. Senior Management Severance Plan filed as Exhibit 10.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on May 7, 2025).
10.14+	Executive Annual Incentive Compensation Plan adopted in February 2021 (incorporated by reference to Exhibit 10.11 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2021).
10.15+	Letter Agreement, by and between the Company and Travis D. Stice, dated February 20, 2025 (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 20, 2025).
10.16	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).
10.17	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).
10.18	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).
10.19	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 Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 27, 2016).
10.20	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 Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 20, 2016).
10.21	Fifth Amendment to the Second Amended and Restated Credit Agreement, dated as of November 28, 2017, 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 4, 2017).
10.22	Sixth Amendment to the Second Amended and Restated Credit Agreement and Third Amendment to Amended and Restated Guaranty and Collateral Agreement, dated as of May 25, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 1, 2018).
10.23	Seventh Amendment to the Second Amended and Restated Credit Agreement, dated as of August 31, 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 September 7, 2018).

Exhibit Number	Description
10.24	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).
10.25	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).
10.26	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. 001-35700, filed by the Company with the SEC on March 29, 2019).
10.27	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).
10.28	Twelfth Amendment to Second Amended and Restated Credit Agreement and First Amendment to Second Amended and Restated Guaranty Agreement, dated as of June 2, 2021, between 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 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 8, 2021).
10.29	Thirteenth Amendment to Second Amended and Restated Credit Agreement, dated as of June 2, 2022, between Diamondback Energy, Inc., as parent guarantor, Diamondback E&P LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 7, 2022).
10.30	Fourteenth Amendment to Second Amended and Restated Credit Agreement, dated as of March 6, 2024, by and among the Company, as borrower, the lenders and other parties party thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 6, 2024).
10.31	Fifteenth Amendment to Second Amended and Restated Credit Agreement, dated as of March 21, 2025, by and among the Company, as borrower, the lenders and other parties party thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No 001-35700, filed by the Company with the SEC on March 21, 2025).
10.32	Sixteenth Amendment to Second Amended and Restated Credit Agreement, dated as of June 12, 2025, by and among the Company, as borrower, the lenders and other parties party thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No 001-35700, filed by the Company with the SEC on June 12, 2025).
10.33	Credit Agreement, dated as of June 12, 2025, by and among Former Viper, the Borrower, the lenders and guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-36505, filed by Former Viper with the SEC on June 12, 2025).
10.34	Term Loan Credit Agreement, dated as of February 29, 2024, by and among the Company, as borrower, the lenders party thereto, and Citibank, N.A., as administrative agent (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 6, 2024).
10.35	Term Loan Credit Agreement, dated as of March 21, 2025, by and among the Company, as borrower, the lenders party thereto, and Bank of America, N.A., as administrative agent (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 21, 2025).
10.36	Term Loan Credit Agreement, dated as of July 23, 2025, by and among Viper Energy Partners LLC, Former Viper, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 001-36505, filed by Former Viper with the SEC on July 23, 2025).

Exhibit Number	Description
10.37	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 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on September 4, 2019).
10.38	Letter Agreement, dated November 28, 2025, by and between Diamondback Energy, Inc., a Delaware corporation, and SGF FANG Holdings, LP, a Delaware limited partnership (incorporated by reference to Exhibit 99.1 to the Form Schedule 13D/A, File No. 005-87028, filed by SGF FANG Holdings, LP with the SEC on December 2, 2025).
19.1	Insider Trading Policy (incorporated by reference to Exhibit 19.1 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 26, 2025).
19.2	Sixth Amended and Restated Supplemental Policy Concerning Trading in Securities of the Company and its Subsidiaries by Certain Designated Persons (incorporated by reference to Exhibit 19.2 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 26, 2025).
21.1*	List of Subsidiaries of Diamondback Energy, Inc.
22.1	List of Issuers and Guarantor Subsidiaries (incorporated by reference to Exhibit 22.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 5, 2021).
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P. with respect to the audit of Diamondback Energy, Inc. estimated reserves.
23.3*	Consent of Ryder Scott Company, L.P. with respect to the audit of Viper Energy, Inc. estimated reserves.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
97.1*	Diamondback Energy, Inc. Clawback Policy.
99.1*	Audit Report of Ryder Scott Company, L.P., dated January 13, 2026, with respect to an audit of the proved reserves, future production and income attributable to certain leasehold interests of Diamondback Energy, Inc. as of December 31, 2025.
99.2*	Audit Report of Ryder Scott Company, L.P., dated January 13, 2026, with respect to an audit of the proved reserves, future production and income attributable to certain royalty interests of Viper Energy, Inc., a subsidiary of Diamondback Energy, Inc., as of December 31, 2025.
101	The following financial information from the Company’s Annual Report on Form 10-K for the year ended December 31, 2025, formatted in Inline XBRL: (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statement of Changes in Stockholders’ Equity, 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(a)(5) 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 Section 13 or 15(d) of the Securities 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, 2026

/s/ Kaes Van't Hof
Kaes Van't Hof
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities 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/ Kaes Van't Hof Kaes Van't Hof	Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2026
/s/ Vincent K. Brooks Vincent K. Brooks	Director	February 25, 2026
/s/ Darin G. Holderness Darin G. Holderness	Director	February 25, 2026
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 25, 2026
/s/ Stephanie K. Mains Stephanie K. Mains	Director	February 25, 2026
/s/ Charles A. Meloy Charles A. Meloy	Director	February 25, 2026
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 25, 2026
/s/ Robert K. Reeves Robert K. Reeves	Director	February 25, 2026
/s/ Lance W. Robertson Lance W. Robertson	Director	February 25, 2026
/s/ Travis D. Stice Travis D. Stice	Executive Chairman of the Board and Director	February 25, 2026
/s/ Melanie M. Trent Melanie M. Trent	Director	February 25, 2026
/s/ Frank D. Tsuru Frank D. Tsuru	Director	February 25, 2026
/s/ Steven E. West Steven E. West	Director	February 25, 2026
/s/ Jere W. Thompson III Jere W. Thompson III	Chief Financial Officer, Executive Vice President (Principal Financial Officer)	February 25, 2026
/s/ Teresa L. Dick Teresa L. Dick	Chief Accounting Officer, Executive Vice President and Assistant Secretary (Principal Accounting Officer)	February 25, 2026

Restricted Stock Unit Award (#) O-RSU26-___

DIAMONDBACK ENERGY, INC.
2021 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD CERTIFICATE

THIS IS TO CERTIFY that Diamondback Energy, Inc., a Delaware corporation (the "***Company***"), has granted you ("***Participant***") time-based Restricted Stock Units under the Company's 2021 Amended and Restated Equity Incentive Plan (the "***Plan***"), as set forth below. Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Plan.

Name of Participant:	________________
Total Number of Restricted Stock Units Granted:	_____________
Date of Grant:	March 1, 2026
Vesting Schedule and Payment/Settlement Dates:	Shares of Common Stock will vest on the Vesting Dates specified below and will be settled within 10 business days after each Vesting Date specified below (the date of such settlements, the "***Payment/Settlement Dates***").

Vesting Date	**# Vested Shares**
March 1, 2026	_______
March 1, 2027	_______
March 1, 2028	_______

By your signature and the signature of the Company's representative below, you and the Company agree to be bound by all of the terms and conditions of the Restricted Stock Unit Award Agreement attached hereto as *Annex I*, and the Plan (both incorporated herein by this reference as if set forth in full in this document). By executing this Certificate, you hereby irrevocably elect to accept the Restricted Stock Unit rights granted pursuant to this Certificate and the related Restricted Stock Unit Award Agreement and to receive the Restricted Stock Units designated above subject to the terms of the Plan, this Certificate, and the Restricted Stock Unit Award Agreement.

In lieu of receiving documents in paper format, by signing below you agree, to the fullest extent permitted by law, to accept electronic delivery of any documents that the Company may be required to deliver (including, without limitation, prospectuses, prospectus supplements, grant or award notifications and agreements, account statements, annual and quarterly reports, and all other forms of communications) in connection with this and any other award made or offered by the Company. Electronic delivery may be via an electronic mail system of the Company or by reference to a location on a Company intranet to which you have access. You hereby consent to any and all procedures the Company has established or may establish for an electronic signature system for delivery and acceptance of any such documents that the Company may be required to deliver, and agree that your electronic signature is the same as, and shall have the same force and effect as, your manual signature.

PARTICIPANT

By: ___________________________________

[Name]

Dated: ______ __, 2026

DIAMONDBACK ENERGY, INC.

By: ___________________________________

Kaes Van't Hof, Chief Executive Officer

Dated: ______ __, 2026

DIAMONDBACK ENERGY, INC.
2021 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD AGREEMENT

This Restricted Stock Unit Award Agreement (this "***Agreement***"), is made and entered into on the execution date of the Restricted Stock Unit Award Certificate to which it is attached (the "***Certificate***"), by and between Diamondback Energy, Inc., a Delaware corporation (the "***Company***"), and the **Participant** named in the Certificate ("***Participant***").

Pursuant to the Diamondback Energy, Inc. 2021 Amended and Restated Equity Incentive Plan (the "***Plan***"), the Administrator has authorized the grant to Participant of the number of Restricted Stock Units set forth in the Certificate (the "***Award***"), upon the terms and subject to the conditions set forth in this Agreement and in the Plan. Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Plan or in the Certificate, as applicable.

NOW, **THEREFORE**, in consideration of the premises and the benefits to be derived from the mutual observance of the covenants and promises contained herein and other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto agree as follows:

1. Basis for Award. This Award is made pursuant to Section 7(a) of the Plan for valid consideration provided to the Company by Participant. By Participant's execution of the Certificate, Participant agrees to accept the Award rights granted pursuant to the Certificate and this Agreement, and to receive the Restricted Stock Units designated in the Certificate subject to the terms of the Plan, the Certificate, and this Agreement.

2. Restricted Stock Units Awarded.

2.1 The Company hereby grants to Participant the number of Restricted Stock Units set forth in the Certificate. Each Restricted Stock Unit represents a right to receive one share of Common Stock from the Company payable in accordance with Section 5 below and any Dividend Equivalents (as defined below) credited to Participant's Restricted Stock Unit Account (as defined below) with respect to that share.

2.2 The Company will, in accordance with the Plan, establish and maintain an account (the "***Restricted Stock Unit Account***") for Participant, and will credit such account for the number of Restricted Stock Units granted to Participant and any Dividend Equivalents as provided in Section 4 below. On any given date, the value of each Restricted Stock Unit will equal the Fair Market Value on such date of one share of Common Stock.

3. Vesting.

3.1 The Restricted Stock Units will vest pursuant to the Vesting Schedule set forth in the Certificate. Except as otherwise provided in a severance plan participation agreement between Participant and the Company or an Affiliate (a "***Severance Agreement***") or as provided in Sections 3.2, 3.3 or 3.4 below, if Participant ceases Continuous Service for any reason, Participant will immediately forfeit the unvested Restricted Stock Units and any securities, other property or amounts nominally credited to the Restricted Stock Unit Account, including any Dividend Equivalents credited to the Restricted Stock Unit Account that have not been settled or paid.

3.2 Except as otherwise provided in a Severance Agreement, in the event of a termination of Participant's Continuous Service (a) by the Company or an Affiliate other than for Cause (and not as a result of Participant's death or Disability) or (b) as a result of Participant's resignation for Good Reason (as defined for purposes of the Company's Senior Management Severance Plan), in either case, upon the consummation of or within 24 months after the occurrence of a Change in Control, (an "***Acceleration Event***"), the unvested Restricted Stock Units, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will vest immediately upon the occurrence of an Acceleration Event.

3.3 Except as otherwise provided in a Severance Agreement, upon a termination of Participant's Continuous Service as a result of Participant's death or Disability, the unvested Restricted Stock Units, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will become 100% vested and will be settled and paid in full within 10 business days following the date of vesting.

3.4 To the extent that a Severance Agreement provides for acceleration of vesting of any or all unvested Restricted Stock Units on termination of Continuous Service that is more favorable to Participant than the provisions of this Agreement, such provisions are incorporated by reference in this Agreement.

4. Dividend Equivalents. If the Company pays any cash dividend on its outstanding Common Stock for which the record date occurs after the Date of Grant, the Administrator will credit the Restricted Stock Unit Account as of the dividend payment date in an amount equal to the amount of the dividend paid by the Company on a single Share multiplied by the number of Restricted Stock Units under this Agreement that are unvested as of that record date and that are vested but have not been settled under the payment terms of Section 5 ("***Dividend Equivalents***"). Except as otherwise provided in Section 3, Dividend Equivalents will vest and be paid to Participant on the dividend payment date if Participant is in Continuous Service or otherwise holds vested but have not been settled Restricted Stock Units on the dividend payment date declared by the Company.

5. Payment/Settlement. Subject to Participant's satisfaction of the applicable withholding requirements pursuant to Section 7 hereof, the Company will settle the Award on the Payment/Settlement Date or Dates set forth in the Certificate by issuing to Participant one share of Common Stock for each Restricted Stock Unit payable on such Payment/Settlement Date (and upon such settlement, the Restricted Stock Units will cease to be credited to the Restricted Stock Unit Account). If the Certificate does not specify a Payment/Settlement Date, the applicable Payment/Settlement Date will be within 10 business days after each vesting date set forth in the Vesting Schedule. If an Acceleration Event occurs, the Payment/Settlement Date will be within 10 business days after the date the Acceleration Event occurs. The Administrator will enter Participant's name as a stockholder of record with respect to such shares of Common Stock on the books of the Company with respect to the shares of Common Stock issued on the applicable Payment/Settlement Date free of all restrictions hereunder, except for applicable federal and state securities law restrictions. Participant acknowledges and agrees that shares of Common Stock may be issued in electronic form as a book entry with the Company's transfer agent and that no physical certificates need be issued. Any securities, other property or amounts nominally credited to the Restricted Stock Unit Account other than Restricted Stock Units will be paid in kind or, in the Administrator's discretion, in cash.

6. Compliance with Laws and Regulations. The issuance and transfer of shares of Common Stock on any Payment/Settlement Date will be subject to the Company's and Participant's full compliance, to the satisfaction of the Company and its counsel, with all applicable requirements of federal, state, and foreign securities laws and with all applicable requirements of any securities exchange on which the Common Stock may be listed at the time of such issuance or transfer. Participant understands that the Company is under no obligation to register or qualify the shares of Common Stock with the U.S. Securities and Exchange Commission ("***SEC***"), any state securities commission, foreign securities regulatory authority, or any securities exchange to effect such compliance.

7. Tax Withholding.

7.1 As a condition to payment under Section 5 hereof, Participant agrees that on or before the Payment/Settlement Date or such other date as required by the Administrator, Participant will pay to the Company any federal, state, or local taxes required by law to be withheld with respect to the Restricted Stock Units for which the restrictions lapse and any related securities, other property or amounts then nominally credited to the Restricted Stock Unit Account.

7.2 Participant will pay the amounts due under this Section 7 to the Company by Stock Withholding or may be paid, at Participant's election, in cash, or (to the extent any applicable insider trading policy, window or restriction does not prohibit Participant from engaging in a sale transaction) by tendering shares of Common Stock held by Participant to a broker selected by the Company for immediate sale and remittance of proceeds equal to the required withholding amount to the Company, including shares that otherwise would be issued and transferred to Participant as payment on the applicable Payment/Settlement Date, with a Fair Market Value on that Payment/Settlement Date that does not exceed the maximum statutory tax rates in the applicable jurisdictions (subject to Participant's written request to withhold more than the minimum required tax withholding in the applicable jurisdictions), or a combination of cash and shares of Common Stock. If Participant fails to make such payments, the Company or its Affiliates will, to the extent permitted by law, have the right to deduct from any payment of any kind otherwise due to Participant any federal, state, or local taxes required by law to be withheld with respect to such payment. Dividend Equivalents credited to the Restricted Stock Unit Account will be subject to withholding at the time of payment.

8. Not Transferrable. Until Common Stock is issued on the applicable Payment/Settlement Date, the Restricted Stock Units, any related Dividend Equivalents credited to the Restricted Stock Unit Account and any related securities, other property or amounts nominally credited to the Restricted Stock Unit Account may not be sold, transferred, or otherwise disposed of, and may not be pledged or otherwise hypothecated other than by will or by the applicable laws of descent and distribution, provided that the Restricted Stock Units and any related Dividend Equivalents credited to the Restricted Stock Unit Account will remain subject to the terms of the Plan, the Certificate and this Agreement.

9. No Right to Continued Service. Nothing in this Agreement or in the Plan imposes or may be deemed to impose, by implication or otherwise, any limitation on any right of the Company or any Affiliate to terminate Participant's Continuous Service at any time.

10. Participant's Representations, Warranties and Acknowledgements. Participant represents and warrants to the Company that Participant has received a copy of the Plan, has read and understands the terms of the Plan, the Certificate, and this Agreement, and agrees to be bound by their terms and conditions. Participant further acknowledges that there may be tax consequences upon the payment of the Restricted Stock Units, disposition of any shares of Common Stock received on a Payment/Settlement Date or payment of any Dividend Equivalents credited to the Restricted Stock Unit Account, and that Participant should consult a tax advisor before such time. Participant agrees to sign such additional documentation as the Company may reasonably require from time to time. Participant acknowledges that he or she is aware that copies of the Plan and the Company's financial statements and information filed by the Company with the SEC are available upon request to the Company, at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549 or by visiting the SEC Internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC.

11. No Interest in Company Assets. All amounts nominally credited to Participant's Restricted Stock Unit Account under this Agreement will continue for all purposes to be part of the general assets of the Company. Participant's interest in the Restricted Stock Unit Account will make Participant only a general, unsecured creditor of the Company.

12. No Stockholder Rights before Delivery. Participant will not have any right, title, or interest in, or be entitled to vote or to receive distributions in respect of, or otherwise be considered the owner of, any of the shares of Common Stock covered by the Restricted Stock Units until the Payment/Settlement Dates specified in the Certificate at which such shares of Common Stock are issued pursuant to Section 5 hereof.

13. Modification. The Agreement may not be amended or otherwise modified except in writing signed by both parties; provided, however, that the Company may unilaterally correct mathematical and typographical errors, and the number of Restricted Stock Units granted hereunder may be amended to reflect the correction of such errors.

14. Interpretation. Any dispute regarding the interpretation of this Agreement must be submitted by Participant or the Company to the Administrator for review. The resolution of such a dispute by the Administrator will be final and binding on the Company and Participant.

15. Entire Agreement. The Plan and the Certificate are incorporated herein by reference. This Agreement, the Certificate, and the Plan constitute the entire agreement of the parties and supersede all prior undertakings and agreements with respect to the subject matter hereof. If any inconsistency or conflict exists between the terms and conditions of this Agreement, the Certificate and the Plan, the Plan will govern.

16. Successors and Assigns. The Company may assign any of its rights under this Agreement. This Agreement will bind and inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer set forth herein, this Agreement is binding upon Participant and Participant's heirs, executors, administrators, legal representatives, successors, and assigns.

17. Governing Law. This Agreement will be governed by and construed in accordance with the laws of the State of Delaware without giving effect to its conflict of law principles. If any provision of this Agreement is determined by a court of law to be illegal or unenforceable, then such provision will be enforced to the maximum extent possible and the other provisions will remain fully effective and enforceable.

EXHIBIT A

Diamondback Energy, Inc. 2021 Amended and Restated Equity Incentive Plan

Restricted Stock Unit Award (#) O-PSU26-___

DIAMONDBACK ENERGY, INC.
2021 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD CERTIFICATE

THIS IS TO CERTIFY that Diamondback Energy, Inc., a Delaware corporation (the "***Company***"), has granted you ("***Participant***") performance-based Restricted Stock Units (this "***Performance Award***") under the Company's 2021 Amended and Restated Equity Incentive Plan (the "***Plan***"), as set forth below. Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Plan.

Name of Participant:	___________________________________
Target Number of Restricted Stock Units Granted:	________
Date of Grant:	___________
Payment/Settlement Dates:	Fully vested Restricted Stock Units will be settled by the payment of shares of Common Stock within 10 business days after the date on which the Committee has made the certification required under Section 7(b)(iv) of the Plan with respect to the performance goals applicable to such Restricted Stock Units (which in any event will be no later than March 15 of the calendar year following the calendar year in which the Performance Period ends).
Performance Period:	January 1, 2026 through December 31, 2028
Performance Vesting Goals and Schedule:	The actual number of Restricted Stock Units with respect to which Participant will be entitled to receive shares of Common Stock will equal the product of (i) the Target Grant Vesting Percentage, multiplied by (ii) the Target Number of Restricted Stock Units Granted, multiplied by (iii) the Absolute TSR Modifier (as defined in *Annex I* attached hereto). The Target Grant Vesting Percentage will be determined based on the attainment of (i) Continuous Service through the last day of the Performance Period, and (ii) achieving the Relative Total Stockholder Return Percentile (as defined in *Annex I* attached hereto) and Company's Absolute Total Stockholder Return performance goals set forth below:

Relative Total Stockholder Return Percentile	Target Grant Vesting Percentage[1]
Below 25th Percentile of Peer Group	0% of Target
Between 25th Percentile of Peer Group and up to but less than 75th Percentile	Straight line interpolation between 50% and 150% of Target
At or above 75th Percentile of Peer Group	200% of Target

Company's Absolute Total Stockholder Return	Absolute TSR Modifier
Below 0%	75%
Between 0% to 15%	100%
Above 15%	125%

By your signature and the signature of the Company's representative below, you and the Company agree to be bound by all of the terms and conditions of the Restricted Stock Unit Award Agreement attached hereto as *Annex II*, and the Plan (both incorporated herein by this reference as if set forth in full in this document). By executing this Certificate, you hereby irrevocably elect to accept the Restricted Stock Unit rights granted pursuant to this Certificate and the related Restricted Stock Unit Award Agreement and to receive the Restricted Stock Units designated above subject to the terms of the Plan, this Certificate, and the Restricted Stock Unit Award Agreement.

In lieu of receiving documents in paper format, by signing below you agree, to the fullest extent permitted by law, to accept electronic delivery of any documents that the Company may be required to deliver (including, without limitation, prospectuses, prospectus supplements, grant or award notifications and agreements, account statements, annual and quarterly reports, and all other forms of communications) in connection with this and any other award made or offered by the Company. Electronic delivery may be via an electronic mail system of the Company or by reference to a location on a Company intranet to which you have access. You hereby consent to any and all procedures the Company has established or may establish for an electronic signature system for delivery and acceptance of any such documents that the Company may be required to deliver, and agree that your electronic signature is the same as, and shall have the same force and effect as, your manual signature.

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[1] Target Grant Vesting Percentage is expressed as a percentage of the Target Number of Restricted Stock Units Granted and, after being adjusted by the Absolute TSR Modifier, may result in a settlement that is in excess of the Target Number of Restricted Stock Units Granted, up to a maximum grant equal to 250% of the Target Number of Restricted Stock Units Granted. The Target Grant Vesting Percentage applicable to Restricted Stock Units earned based on Relative Total Stockholder Return Percentile criteria will be interpolated on a straight line basis between 50% and 150% if actual performance is at or above the 25th percentile but less than the 75th percentile.

PARTICIPANT

____

Dated: [_________________], 2026

DIAMONDBACK ENERGY, INC.

By: ________________________________
Kaes Van't Hof, Chief Executive Officer

Dated: [_________________], 2026

Definition of "Relative Total Stockholder Return Percentile"

For purposes of this Performance Award, "***Relative Total Stockholder Return Percentile***" means for the Performance Period, the Total Stockholder Return (as defined below) of the Company in comparison to the Total Stockholder Return for each of the companies comprising the Peer Group (as defined below). How the Company's Total Stockholder Return ranks by percentile relative to the Total Stockholder Return of the other Peer Group companies determines whether the Restricted Stock Unit Target Award vests and how many shares of Common Stock are paid out, as set forth in this Performance Award.

The Company's percentile ranking among the Peer Group Total Stockholder Return is calculated by ranking the Company's Total Stockholder Return as part of the Total Stockholder Return for the Peer Group as a whole.

"***Total Stockholder Return***" for the Company and each member of the Peer Group is determined over a particular measurement period by: dividing (1) the sum of (a) the cumulative value of dividends received during the measurement period, assuming reinvestment, plus (b) the difference between the average share price for the month of December 2028 compared to the average share price for month of December 2025; by (2) the average share price for the month of December 2025. For this purpose, we assume dividends are reinvested in stock at market prices at approximately the same time actual dividends are paid. Stockholder return is quoted on an annualized basis. This is expressed as a compound annual growth rate percentage calculated as TSR = (Pe – Pb + Dividends)/Pb where:

Pb = average share price for the month of December 2025;

Pe = average share price for the month of December 2028,

Dividends = dividends paid over the Performance Period; and

TSR = Total Stockholder Return.

The Company's "***Peer Group***" consists of the following members:

(a) each of the following companies: APA Corporation (APA); Chevron Corporation (CVX); ConocoPhillips Company (COP); Devon Energy Corporation (DVN); EOG Resources, Inc. (EOG); Matador Resources Company (MTDR); Ovintiv Inc. (OVV); Occidental Petroleum (OXY); Permian Resources (PR);

(b) the SPDR S&P Oil & Gas Exploration & Production ETF Index (XOP) (weighted once); and

(c) the S&P 500 Index (SPX) (weighted once).

If during the Performance Period a member of the Company's Peer Group publicly announces it has entered into a definitive agreement with respect to an acquisition transaction and subsequent to the consummation of such transaction such peer ceases to be a publicly traded company, then (subject to the Compensation Committee's right as Administrator of the Plan to exercise discretion to make any appropriate further adjustments taking into account all relevant information at the time) the Total Stockholder Return for such peer shall be calculated such that "Pe" in the formula above shall equal the closing share price for such peer on the date such peer first publicly announces such transaction (or the date immediately following such date if such transaction is announced after market).

In addition, if during the Performance Period a member of the Company's Peer Group experiences a bankruptcy or becomes insolvent, such Peer Group member will remain a part of the Peer Group and its Total Stockholder Return will be –100%.

Definition of "Absolute TSR Modifier"

For purposes of this Performance Award, "***Absolute TSR Modifier***" means the percentage determined for the Performance Period as specified in the schedule set forth above based on the Company's absolute Total Stockholder Return for the Performance Period.

DIAMONDBACK ENERGY, INC.
2021 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD AGREEMENT

This Restricted Stock Unit Award Agreement (this "***Agreement***"), is made and entered into on the execution date of the Restricted Stock Unit Award Certificate to which it is attached (the "***Certificate***"), by and between Diamondback Energy, Inc., a Delaware corporation (the "***Company***"), and the **Participant** named in the Certificate ("***Participant***").

Pursuant to the Diamondback Energy, Inc. 2021 Amended and Restated Equity Incentive Plan (the "***Plan***"), the Administrator has authorized the grant to Participant of the number of Restricted Stock Units set forth in the Certificate (the "***Award***"), upon the terms and subject to the conditions set forth in this Agreement and in the Plan. Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Plan or in the Certificate, as applicable.

NOW, **THEREFORE**, in consideration of the premises and the benefits to be derived from the mutual observance of the covenants and promises contained herein and other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto agree as follows:

1. Basis for Award. This Award is made pursuant to Section 7(a) of the Plan for valid consideration provided to the Company by Participant. By Participant's execution of the Certificate, Participant agrees to accept the Award rights granted pursuant to the Certificate and this Agreement, and to receive the Restricted Stock Units designated in the Certificate subject to the terms of the Plan, the Certificate and this Agreement.

2. Restricted Stock Units Awarded.

2.1 The Company hereby grants to Participant the target number of Restricted Stock Units set forth in the Certificate. Each Restricted Stock Unit represents a right to receive one share of Common Stock from the Company payable in accordance with Section 5 below and any Dividend Equivalents (as defined below) credited to Participant's Restricted Stock Unit Account (as defined below) with respect to that share; provided, however, that depending on the level attained with respect to the Performance Vesting Goals and Schedules set forth in the Certificate, the number of shares of Common Stock that may be earned hereunder may range from 0% to 250% of the target number of Restricted Stock Units.

2.2 The Company will, in accordance with the Plan, establish and maintain an account (the "***Restricted Stock Unit Account***") for Participant, and will credit such account for the target number of Restricted Stock Units granted to Participant and any Dividend Equivalents as provided in Section 4 below. On any given date, the value of each Restricted Stock Unit will equal the Fair Market Value on such date of one share of Common Stock.

3. Vesting.

3.1 The Restricted Stock Units will vest based on the Target Grant Vesting Percentage as adjusted by the Absolute TSR Modifier, in each case, as determined under the Performance Vesting Goals and Schedules set forth in the Certificate. Except as otherwise provided in a severance plan participation agreement between Participant and the Company or an Affiliate (a "***Severance Agreement***") or as provided in Sections 3.2, 3.3 or 3.4 below, if Participant ceases Continuous Service for any reason prior to the end of the Performance Period, Participant will immediately forfeit all the unvested Restricted Stock Units and any securities, other property or amounts nominally credited to the Restricted Stock Unit Account, including any Dividend Equivalents credited to the Restricted Stock Unit Account that have not been settled or paid.

3.2 Except as otherwise provided in a Severance Agreement, in the event of a termination of Participant's Continuous Service (a) by the Company or an Affiliate other than for Cause (and not as a result of Participant's death or Disability) or (b) Participant's resignation for Good Reason (as defined for purposes of the Company's Senior Management Severance Plan), in either case, upon the consummation of or within 24 months after the occurrence of a Change in Control, (an "***Acceleration Event***"), the Relative Total Stockholder Return Percentile and Absolute TSR Modifier used to determine the number of Restricted Stock Units that will become vested on the Acceleration Event will be determined based on a Performance Period that ends on the last trading day of the month preceding the date the Change in Control is consummated (the "***Accelerated Performance Period***"). The Total Stockholder Return of each member of the Peer Group will be measured based on the reported closing stock price on the principal exchange on the last day of the Accelerated Performance Period, and the Total Stockholder Return of the Company will be measured on the last day of the Accelerated Performance Period based on the price per share payable to stockholders of the Company in connection with the Change in Control. The number of shares determined based on the Relative Total Stockholder Return Percentile for the Accelerated Performance Period, as adjusted by the Absolute TSR Modifier, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will vest immediately upon the occurrence of such Acceleration Event.

3.3 Upon a termination of Participant's Continuous Service as a result of Participant's death or Disability, the Target Grant Vesting Percentage will be determined at the end of the Performance Period and the Restricted Stock Units, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will be settled and paid at the same Payment/Settlement Date as if Participant remained in Continuous Service through the end of the Performance Period.

3.4 To the extent that a Severance Agreement provides for acceleration of vesting of any or all unvested Restricted Stock Units on termination of Continuous Service that is more favorable to Participant than the provisions of this Agreement, such provisions are incorporated by reference in this Agreement.

4. **Dividend Equivalents**. If the Company pays any cash dividend on its outstanding Common Stock for which the record date occurs after the Date of Grant, the Administrator will credit the Restricted Stock Unit Account as of the dividend payment date in an amount equal to the amount of the dividend paid by the Company on a single Share multiplied by the number of Restricted Stock Units under this Agreement that are unvested (based on the Target Number of Restricted Stock Units Granted) as of that record date and such number of Restricted Stock Units that are vested but have not been settled under the payment terms of Section 5 ("***Dividend Equivalents***"). Except as otherwise provided in Section 3, Dividend Equivalents will vest and be paid to Participant on the dividend payment date if Participant is in Continuous Service or otherwise holds vested but have not been settled Restricted Stock Units on the dividend payment date declared by the Company.

5. **Payment/Settlement**. Subject to Participant's satisfaction of the applicable withholding requirements pursuant to Section 7 hereof, the Company will settle the Award on the Payment/Settlement Date or Dates set forth in the Certificate by issuing to Participant one share of Common Stock for each Restricted Stock Unit payable on such Payment/Settlement Date (and upon such settlement, the Restricted Stock Units will cease to be credited to the Restricted Stock Unit Account). If the Certificate does not specify a Payment/Settlement Date, the applicable Payment/Settlement Date will be the date within 10 business days after the Committee has made the certification required under Section 7(b)(iv) of the Plan with respect to the performance goals applicable to such Restricted Stock Units (which in any event will be no later than March 15 of the calendar year following the calendar year in which the Performance Period ends). If an Acceleration Event occurs, the Payment/Settlement Date will be within 10 business days after the date the Acceleration Event occurs. The Administrator will enter Participant's name as a stockholder of record with respect to such shares of Common Stock on the books of the Company with respect to the shares of Common Stock issued on the applicable Payment/Settlement Date free of all restrictions hereunder, except for applicable federal and state securities law restrictions. Participant acknowledges and agrees that shares of Common Stock may be issued in electronic form as a book entry with the Company's transfer agent and that no physical certificates need be issued. Any securities, other property or amounts nominally credited to the Restricted Stock Unit Account other than Restricted Stock Units will be paid in kind or, in the Administrator's discretion, in cash.

6. **Compliance with Laws and Regulations**. The issuance and transfer of shares of Common Stock on any Payment/Settlement Date will be subject to the Company's and Participant's full compliance, to the satisfaction of the Company and its counsel, with all applicable requirements of federal, state, and foreign securities laws and with all applicable requirements of any securities exchange on which the Common Stock may be listed at the time of such issuance or transfer. Participant understands that the Company is under no obligation to register or qualify the shares of Common Stock with the U.S. Securities and Exchange Commission ("***SEC***"), any state securities commission, foreign securities regulatory authority, or any securities exchange to effect such compliance.

7. Tax Withholding.

7.1 As a condition to payment under Section 5 hereof, Participant agrees that on or before the Payment/Settlement Date or such other date as required by the Administrator, Participant will pay to the Company any federal, state, or local taxes required by law to be withheld with respect to the Restricted Stock Units for which the restrictions lapse and any related securities, other property or amounts then nominally credited to the Restricted Stock Unit Account.

7.2 Participant will pay the amounts due under this Section 7 to the Company by Stock Withholding, or may be paid at Participant's election, in cash, or (to the extent any applicable insider trading policy, window or restriction does not prohibit Participant from engaging in a sale transaction) by tendering shares of Common Stock held by Participant to a broker selected by the Company for immediate sale and remittance of proceeds equal to the required withholding amount to the Company, including shares that otherwise would be issued and transferred to Participant as payment on the applicable Payment/Settlement Date, with a Fair Market Value on that Payment/Settlement Date that does not exceed the maximum statutory tax rates in the applicable jurisdictions (subject to Participant's written request to withhold more than the minimum required tax withholding in the applicable jurisdictions), or a combination of cash and shares of Common Stock. If Participant fails to make such payments, the Company or its Affiliates will, to the extent permitted by law, have the right to deduct from any payment of any kind otherwise due to Participant any federal, state, or local taxes required by law to be withheld with respect to such payment. Dividend Equivalents credited to the Restricted Stock Unit Account will be subject to withholding at the time of payment.

8. Not Transferrable. Until Common Stock is issued on the applicable Payment/Settlement Date, the Restricted Stock Units, any related Dividend Equivalents credited to the Restricted Stock Unit Account and any related securities, other property or amounts nominally credited to the Restricted Stock Unit Account may not be sold, transferred, or otherwise disposed of, and may not be pledged or otherwise hypothecated other than by will or by the applicable laws of descent and distribution, provided that the Restricted Stock Units and any related Dividend Equivalents credited to the Restricted Stock Unit Account will remain subject to the terms of the Plan, the Certificate and this Agreement.

9. No Right to Continued Service. Nothing in this Agreement or in the Plan imposes or may be deemed to impose, by implication or otherwise, any limitation on any right of the Company or any Affiliate to terminate Participant's Continuous Service at any time.

10. Participant's Representations, Warranties and Acknowledgements. Participant represents and warrants to the Company that Participant has received a copy of the Plan, has read and understands the terms of the Plan, the Certificate and this Agreement and agrees to be bound by their terms and conditions. Participant further acknowledges that there may be tax consequences upon the payment of the Restricted Stock Units, payment of any Dividend Equivalents credited to the Restricted Stock Unit Account or disposition of any shares of Common Stock received on a Payment/Settlement Date, and that Participant should consult a tax advisor before such time. Participant agrees to sign such additional documentation as the Company may reasonably require from time to time. Participant acknowledges that he or she is aware that copies of the Plan and the Company's financial statements and information filed by the Company with the SEC are available upon request to the Company, at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549 or by visiting the SEC Internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC.

11. No Interest in Company Assets. All amounts nominally credited to Participant's Restricted Stock Unit Account under this Agreement will continue for all purposes to be part of the general assets of the Company. Participant's interest in the Restricted Stock Unit Account will make Participant only a general, unsecured creditor of the Company.

12. No Stockholder Rights before Delivery. Participant will not have any right, title, or interest in, or be entitled to vote or to receive distributions in respect of, or otherwise be considered the owner of, any of the shares of Common Stock covered by the Restricted Stock Units until the Payment/Settlement Dates specified in the Certificate at which such shares of Common Stock are issued pursuant to Section 5 hereof.

13. Modification. The Agreement may not be amended or otherwise modified except in writing signed by both parties; provided, however, that the Company may unilaterally correct mathematical and typographical errors, and the number of Restricted Stock Units granted hereunder may be amended to reflect the correction of such errors.

14. Interpretation. Any dispute regarding the interpretation of this Agreement must be submitted by Participant or the Company to the Administrator for review. The resolution of such a dispute by the Administrator will be final and binding on the Company and Participant.

15. Entire Agreement. The Plan and the Certificate are incorporated herein by reference. This Agreement, the Certificate, and the Plan constitute the entire agreement of the parties and supersede all prior undertakings and agreements with respect to the subject matter hereof. If any inconsistency or conflict exists between the terms and conditions of this Agreement, the Certificate, and the Plan, the Plan will govern.

16. Successors and Assigns. The Company may assign any of its rights under this Agreement. This Agreement will bind and inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer set forth herein, this Agreement is binding upon Participant and Participant's heirs, executors, administrators, legal representatives, successors, and assigns.

17. Clawback. Notwithstanding any provision in this Agreement to the contrary, if required by Listing Standard 5608 adopted by The Nasdaq Stock Market to implement Rule 10D-1 under the Securities Exchange Act of 1934, as amended, the Sarbanes-Oxley Act of 2002 or by other applicable law or Company policy in effect from time to time, the Award shall be conditioned on repayment or forfeiture in accordance with such applicable laws and/or Company policy. By accepting the Award, Participant consents to any such clawback, repayment or forfeiture condition.

18. Governing Law. This Agreement will be governed by and construed in accordance with the laws of the State of Delaware without giving effect to its conflict of law principles. If any provision of this Agreement is determined by a court of law to be illegal or unenforceable, then such provision will be enforced to the maximum extent possible and the other provisions will remain fully effective and enforceable.

EXHIBIT A

Diamondback Energy, Inc. 2021 Amended and Restated Equity Incentive Plan

Exhibit 21.1

Diamondback Energy, Inc.
Significant Subsidiaries of Registrant

Name of Subsidiary	Jurisdiction of Incorporation
Diamondback E&P LLC	Delaware
Eclipse Merger Sub II, LLC	Delaware
Endeavor Energy Resources, L.P.	Texas
QEP Energy Company	Delaware
Viper Energy Partners LP	Delaware
VNOM Holding Company LLC	Delaware
Western Coachwhip LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 25, 2026, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Diamondback Energy, Inc. on Form 10-K for the year ended December 31, 2025. We consent to the incorporation by reference of said reports in the Registration Statements of Diamondback Energy, Inc. on Forms S-3 (File No. 333-282225; File No. 333-286424; and File No. 333-291708) and on Forms S-8 (File No. 333-188552; File No. 333-215798; File No. 333-228637; File No. 333-235671; and File No. 333-257561).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 25, 2026

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our summary report dated January 13, 2026 on the audit of estimated quantities of proved reserves, future production and income attributable to certain leasehold interest of Diamondback Energy, Inc. ("Diamondback") as of December 31, 2025. As independent oil and gas consultants, we hereby consent to the inclusion of our audit report and the information contained therein and information from our prior reserve reports referenced in this Annual Report on Form 10-K of Diamondback (this "Annual Report") and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such reports and the information contained therein in the Registration Statements of Diamondback on Forms S-3ASR (File No. 333-282225; File No. 333-286424; and File No. 333-291708) and on Forms S-8 (File No. 333-188552; File No. 333-215798; File No. 333-228637; File No. 333-235671; and File No. 333-257561).

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas

February 25, 2026

Exhibit 23.3

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our summary report dated January 13, 2026 on the audit of estimated quantities of proved reserves, future production and income attributable to certain royalty interests of Viper Energy, Inc., a subsidiary of Diamondback Energy, Inc. (“Diamondback”), as of December 31, 2025. As independent oil and gas consultants, we hereby consent to the inclusion of our audit report and the information contained therein and information from our prior reserve reports referenced in this Annual Report on Form 10-K of Diamondback (this “Annual Report”) and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such reports and the information contained therein in the Registration Statements of Diamondback on Forms S-3ASR (File No. 333-282225; File No. 333-286424; and File No. 333-291708) and on Forms S-8 (File No. 333-188552; File No. 333-215798; File No. 333-228637; File No. 333-235671; and File No. 333-257561).

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas

February 25, 2026

EXHIBIT 31.1

CERTIFICATION

I, Kaes Van't Hof, certify that:

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

Date: February 25, 2026

/s/ Kaes Van't Hof
Kaes Van't Hof
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Jere W. Thompson III, certify that:

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

Date: February 25, 2026

/s/ Jere W. Thompson III

Jere W. Thompson III
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF PERIOD REPORT

I, Kaes Van't Hof, Chief Executive Officer of Diamondback Energy, Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2025 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date:	February 25, 2026	/s/ Kaes Van't Hof
		Kaes Van't Hof
		Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION OF PERIOD REPORT

I, Jere W. Thompson III, Chief Financial Officer of Diamondback Energy, Inc. (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 25, 2026

/s/ Jere W. Thompson III

Jere W. Thompson III
Chief Financial Officer

Exhibit 97.1

DIAMONDBACK ENERGY, INC.
CLAWBACK POLICY

(Effective Date: February 4, 2026)

Purpose

Diamondback Energy, Inc. (the "***Company***") is committed to conducting business with integrity, in accordance with high ethical standards and in compliance with all applicable laws, rules and regulations, including those regarding the presentation of the Company's financial information to the public. As a result, the Board of Directors of the Company (the "***Board***") has adopted this Clawback Policy (as amended from time to time, this "***Policy***") effective as of the Effective Date set forth above, which replaces and supersedes that certain Clawback Policy dated October 2, 2023.

Administration

This Policy is administered by the Compensation Committee of the Board (the "***Committee***") and is intended to comply with, and as applicable to be administered and interpreted consistent with, and subject to the exceptions set forth in, Listing Standard 5608 adopted by the Nasdaq Stock Market to implement Rule 10D-1 under the Securities Exchange Act of 1934, as amended (collectively, "***Rule 10D-1***"). Except as limited by law, the Committee has full power, authority, and discretion to construe, interpret and apply this Policy. Any determinations made by the Committee will be made in compliance with the Nasdaq Stock Market listing rules and Rule 10D-1 and are final, conclusive and binding on all affected individuals.

This Policy will be interpreted and applied in a manner that is consistent with the requirements of the Nasdaq Stock Market listing rules and Rule 10D-1, and to the extent this Policy is inconsistent with such rules, it shall be deemed amended to the extent necessary to ensure it is consistent therewith. The Board or Committee may amend, modify or terminate this Policy in whole or in part at any time in its sole discretion and may adopt such rules and procedures that it deems necessary or appropriate to implement this Policy or to comply with applicable laws and regulations. In addition, this Policy will terminate automatically when the Company does not have a class of securities listed on a national securities exchange or association and will be limited to the extent that any provision of the Nasdaq Stock Market listing rules and/or Rule 10D-1 is no longer in effect or applicable to the Company. The Company is authorized to take appropriate steps to implement this Policy with respect to Incentive-Based Compensation arrangements with Covered Executives.

Recoupment of Incentive-Based Compensation

In the event the Company is required to prepare an accounting restatement of the Company's financial statements due to material non-compliance with any financial reporting requirement under the federal securities laws that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period, the Company will recover on a reasonably prompt basis the amount of any Incentive-Based Compensation Received by a Covered Executive during the Recovery Period that exceeds the amount that otherwise would have been Received had it been determined based on the restated financial statements.

If the Committee determines the amount of Incentive-Based Compensation Received by a Covered Executive during a Recovery Period exceeds the amount that would have been Received if determined or calculated based on the Company's restated financial results, such excess amount of Incentive-Based Compensation shall be subject to recoupment by the Company pursuant to this Policy. For Incentive-Based Compensation based on stock price or total shareholder return, where the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in an accounting restatement, the Committee will determine the amount based on a reasonable estimate of the effect of the accounting restatement on the relevant stock price or total shareholder return. In all cases, the calculation of the excess amount of Incentive-Based Compensation to be recovered will be determined without regard to any taxes paid with respect to such compensation. The Company will maintain and will provide to the Nasdaq Stock Market documentation of all determinations and actions taken in complying with this Policy. Any determinations made by the Committee under this Policy shall be final and binding on all affected individuals.

The Company may effect any recovery pursuant to this Policy by requiring payment of such amount(s) to the Company, by set-off, by reducing future compensation, or by such other means or combination of means as the Committee determines to be appropriate and to the extent permitted by law. The Company need not recover the excess amount of Incentive-Based Compensation if and to the extent that the Committee determines that such recovery is "impracticable," within the meaning of, subject to and in accordance with any applicable exceptions under the Nasdaq Stock Market listing rules, and not required under Rule 10D-1, including if the Committee determines that the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered after making a reasonable attempt to recover such amounts.

Definitions

"***Covered Executives***" means any "officer" of the Company as defined under Rule 16a-1(f) under the Securities Exchange Act of 1934, as amended.

"***Incentive-Based Compensation***" means any compensation granted, earned, or vested based in whole or in part on the Company's attainment of a financial reporting measure that was Received by a person (i) on or after October 2, 2023 and after the person began service as a Covered Executive, (ii) who served as a Covered Executive at any time during the performance period for the Incentive-Based Compensation, and (iii) while the Company has a class of securities listed on a national securities exchange or association. A financial reporting measure is (i) any measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements and any measure derived wholly or in part from such a measure, and (ii) any measure based in whole or in part on the Company's stock price or total shareholder return.

Incentive-Based Compensation is deemed to be "***Received***" in the fiscal period during which the relevant financial reporting measure is attained, regardless of when the compensation is actually paid or awarded.

"***Recovery Period***" means the three completed fiscal years immediately preceding the date that the Company is required to prepare the accounting restatement described in this Policy, all as determined pursuant to the Nasdaq Stock Market listing rules and Rule 10D-1, and any transition period (that results from a change in the Company's fiscal year) of less than nine months that is within or immediately following such three fiscal years.

Not Exclusive; Limitation on Duplicative Recovery

Any reimbursement or cancellation under this Policy is in addition to, and not in lieu of, any other remedies or rights that may be available to the Company, including (i) pursuant to the terms of any Company plan or policy or any agreement with the Covered Executive, (ii) disciplinary action up to and including termination, and (iii) institution of civil or criminal proceedings. Any right of recoupment under this Policy is in addition to, and is not in lieu of, any actions imposed by law enforcement agencies, regulators or other authorities. Notwithstanding the generality of the foregoing, to the extent that the requirements under the provisions of Section 304 of the Sarbanes-Oxley Act of 2002 are broader than the provisions in this Policy, the provisions of such law will apply to the Company's Chief Executive Officer and Chief Financial Officer. Notwithstanding the foregoing, unless otherwise prohibited by the Nasdaq Stock Market listing rules and/or Rule 10D-1, to the extent this Policy provides for recovery of erroneously awarded Incentive-Based Compensation already recovered by the Company pursuant to Section 304 of the Sarbanes-Oxley Act of 2002, the amount of erroneously awarded Incentive-Based Compensation already recovered by the Company from the recipient of such erroneously awarded Incentive-Based Compensation will be credited to the amount of erroneously awarded Incentive-Based Compensation required to be recovered pursuant to this Policy from such person.

No Indemnification; No Personal Liability

The Company will not indemnify any Covered Executive against any loss pursuant to this Policy, nor will the Company pay, agree to pay, or reimburse any insurance premium to cover any loss hereunder. No member of the Committee or the Board shall have any personal liability to any person as a result of actions taken under this Policy and each member of the Committee and the Board will be fully indemnified by the Company to the fullest extent available under applicable law and the Company's governing documents with respect to any actions taken under this Policy. The foregoing sentence will not limit any other rights to indemnification of the members of the Board under applicable law and the Company's governing documents and contracts.

Severability

The provisions in this Policy are intended to be applied to the fullest extent of the law; provided, however, to the extent that any provision of this Policy is found to be unenforceable or invalid under any applicable law, such provision will be applied to the maximum extent permitted, and shall automatically be deemed amended in a manner consistent with its objectives to the extent necessary to conform to any limitations required under applicable law.

DIAMONDBACK ENERGY, INC.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2025

/s/ Marsha E. Wellmann	/s/ Raza Rizvi
Marsha E. Wellmann, P.E.	Raza Rizvi
TBPELS License No. 116149	Senior Petroleum Engineer
Managing Senior Vice President	

[SEAL]

/s/ James Wells
James Wells
Senior Petroleum Engineer

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 13, 2026

Diamondback Energy, Inc.
500 West Texas, Suite 1210
Midland, Texas 79701

Ladies and Gentlemen:

At the request of Diamondback Energy, Inc. (Diamondback), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves, future production and discounted future net income as of December 31, 2025 prepared by Diamondback's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 7, 2026 and presented herein, was prepared for public disclosure by Diamondback in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves and income data shown herein represent Diamondback's estimated net reserves and income data attributable to the leasehold and royalty interests in certain properties owned by Diamondback and the portion of those reserves and income data reviewed by Ryder Scott, as of December 31, 2025. The properties reviewed by Ryder Scott incorporate Diamondback reserves determinations and are located in the states of New Mexico and Texas.

The properties reviewed by Ryder Scott represent 100 percent of Diamondback's total net proved liquid hydrocarbon and gas reserves as of December 31, 2025.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Diamondback, it is our opinion that the overall procedures and methodologies utilized by Diamondback in preparing their estimates of the proved reserves, future production and discounted future net income as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves, future production and discounted future net income for the reviewed properties as estimated by Diamondback are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves and future net income amounts presented in this report are related to hydrocarbon prices. Diamondback has informed us that in the preparation of their reserves and income projections, as of December 31, 2025, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves and net income data as estimated by Diamondback attributable to Diamondback's interest in properties that we reviewed are summarized below:

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Royalty Interests of
Diamondback Energy Inc.
As of December 31, 2025

	Proved		
	Developed Producing	Undeveloped	Total Proved
Audited by Ryder Scott			
Net Reserves			
Oil/Condensate – MBBLS	1,026,600	554,614	1,581,215
Plant Products – MBBLS	617,717	239,968	857,685
Gas – MMCF	3,360,058	1,277,478	4,637,536
MBOE	2,204,327	1,007,495	3,211,822
Income Data ($M)			
Future Gross Revenue	$78,561,753	$40,144,166	$118,705,919
Deductions	33,443,872	19,143,921	52,587,793
Future Net Income (FNI)	$45,117,881	$21,000,245	$ 66,118,126
Discounted FNI @ 10%	$25,646,325	$10,841,349	$ 36,487,675

Values may not sum to total due to rounding.

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBBLS). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, discounted future net income data are expressed as thousands of U.S. dollars ($M).

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs, and certain abandonment costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Diamondback’s request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and 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 individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves prepared by Diamondback for the properties that we reviewed were estimated by performance methods, analogy, or a combination of methods. In general, the reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through December, 2025 in those cases where such data were considered to be definitive. The data used in these analyses were furnished to Ryder Scott by Diamondback or obtained from public data sources and were considered sufficient for the purpose thereof. In certain cases, producing reserves were estimated by analogy or a combination of methods. These methods were 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 estimates was considered to be inappropriate.

The reserves prepared by Diamondback attributable to the undeveloped status category that we reviewed were estimated by analogy.

To estimate economically producible proved oil and gas reserves and related future net cash flows, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Diamondback relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Diamondback for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2025 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Diamondback for the geographic area reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used by Diamondback to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by Diamondback were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback.

The table below summarizes Diamondback's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Diamondback's "average realized prices." The average realized prices shown in the table below were determined from Diamondback's estimate of the total future gross revenue before production taxes for the properties reviewed by us and Diamondback's estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$65.34/Bbl	$65.01/Bbl
	NGLs	WTI Cushing	$65.34/Bbl	$18.85/Bbl
	Gas	Henry Hub	$3.387/MMBTU	$1.33/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Diamondback's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Diamondback are based on the operating expense reports of Diamondback and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements**.** The operating costs furnished by Diamondback were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Diamondback are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Diamondback were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback.

The estimated cost of abandonment was included by Diamondback for properties where certain abandonment costs were provided by Diamondback and for which they requested be included in our report. Diamondback's estimates of the abandonment costs were accepted without independent verification. We have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by Diamondback and included herein.

The proved undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Diamondback's plans to develop these reserves as of December 31, 2025. The implementation of Diamondback's development plans as presented to us is subject to the approval process adopted by Diamondback's management. As the result of our inquiries during the course of our review, Diamondback has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Diamondback's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Diamondback. Diamondback has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Diamondback has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2025, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Diamondback were held constant throughout the life of the properties.

Diamondback's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were based on analog well performance and type-curves where appropriate. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Diamondback to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Diamondback. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Diamondback's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Diamondback's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Diamondback owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Diamondback for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Diamondback are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Diamondback has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Diamondback's forecast of future proved production and income, we have relied upon data furnished by Diamondback with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, certain abandonment costs, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Diamondback. We consider the factual data furnished to us by Diamondback to be appropriate and sufficient for the purpose of our review of Diamondback's estimates of reserves and future net income. In summary, we consider the assumptions, data, methods and analytical procedures used by Diamondback and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Diamondback, it is our opinion that the overall procedures and methodologies utilized by Diamondback in preparing their estimates of the proved reserves, future production and discounted future net income as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves, future production and discounted future net income for the reviewed properties as estimated by Diamondback are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Diamondback in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Diamondback's estimates of proved reserves, future production and discounted future net income for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Diamondback's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Diamondback when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves, future production and discounted future net income owned by Diamondback.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Diamondback. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Diamondback.

Diamondback makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Diamondback has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 of Diamondback, of the references to our name, as well as to the references to our third party report for Diamondback, which appears in the December 31, 2025 annual report on Form 10-K of Diamondback.

Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Diamondback.

We have provided Diamondback with a digital version of the original signed copy retained in our files. In the event there are any differences between the digital version included in filings made by Diamondback and the original signed copy in our files, the original signed file copy shall control and supersede.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Marsha E. Wellmann

Marsha E. Wellmann, P.E.
TBPELS License No. 116149
Managing Senior Vice President

[SEAL]

/s/ Raza Rizvi

Raza Rizvi
Senior Petroleum Engineer

/s/ James Wells

James Wells
Senior Petroleum Engineer

MEW-RR-JW (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Ms. Marsha E. Wellmann was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Ms. Wellmann, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2012, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies throughout North America and the Gulf of Mexico. Before joining Ryder Scott, Ms. Wellmann served in a number of engineering positions. For more information regarding Ms. Wellmann geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Ms. Wellmann earned a Bachelor of Science degree in Petroleum Engineering and a Business Foundations Certificate from The University of Texas at Austin in 2002 and is a registered Professional Engineer in the State of Texas. She is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Ms. Wellmann fulfills. As part of her 2025 continuing education hours, Ms. Wellmann attended 29 hours of formalized training including various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on her educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Ms. Wellmann has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.2

VIPER ENERGY, INC.

Estimated

Future Reserves and Income

Attributable to Certain

Royalty Interests

SEC Parameters

As of

December 31, 2025

/s/ Marsha E. Wellmann	/s/ Raza Rizvi
Marsha E. Wellmann, P.E.	Raza Rizvi
TBPELS License No. 116149	Senior Petroleum Engineer
Managing Senior Vice President	

[SEAL]

/s/ James Wells
James Wells
Senior Petroleum Engineer

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 13, 2026

Viper Energy, Inc.
c/o Diamondback Energy, Inc.
500 West Texas, Suite 1210
Midland, Texas 79701

Ladies and Gentlemen:

At the request of Diamondback Energy, Inc. (Diamondback), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves, future production and discounted future net income attributable to Viper Energy, Inc. (Viper), a subsidiary of Diamondback Energy, Inc., as of December 31, 2025, and prepared by Diamondback's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 7, 2026 and presented herein, was prepared for public disclosure by Diamondback in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves and income data shown herein represent Diamondback's estimated net reserves and income data attributable to the royalty interests in certain properties owned by Viper and the portion of those reserves and income data reviewed by Ryder Scott, as of December 31, 2025. The properties in which Viper owns an interest and reviewed by Ryder Scott are located in the states of Colorado, Montana, North Dakota, New Mexico, Texas and Wyoming.

The properties reviewed by Ryder Scott represent 100 percent of Viper's total net proved liquid hydrocarbon and gas reserves as of December 31, 2025.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Diamondback, it is our opinion that the overall procedures and methodologies utilized by Diamondback in preparing their estimates of the proved reserves, future production and discounted future net income as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves, future production and discounted future net income for the reviewed properties as estimated by Diamondback are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves and future net income amounts presented in this report are related to hydrocarbon prices. Diamondback has informed us that in the preparation of their reserves and income projections, as of December 31, 2025, they used average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves and net income data as estimated by Diamondback attributable to Viper's interest in properties that we reviewed are summarized below:

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Royalty Interests of
Viper Energy, Inc.
As of December 31, 2025

	Proved		
	Developed Producing	Undeveloped	Total Proved
Audited by Ryder Scott			
Net Reserves			
Oil/Condensate – MBBLS	147,036	46,170	193,206
Plant Products – MBBLS	84,282	22,499	106,781
Gas – MMCF	512,302	123,983	636,285
MBOE	316,702	89,333	406,035
Income Data ($M)			
Future Gross Revenue	$11,168,455	$3,407,380	$14,575,835
Deductions	210,809	67,668	278,477
Future Net Income (FNI)	$10,957,646	$3,339,712	$14,297,358
Discounted FNI @ 10%	$ 5,459,102	$1,922,975	$ 7,382,078

Values may not sum to total due to rounding.

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBBLS). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, discounted future net income data are expressed as thousands of U.S. dollars ($M).

The future gross revenue is after the deduction of production taxes. Because the interests evaluated herein are royalty interests, the deductions include only ad valorem taxes, while the normal direct costs of operating the wells and development costs are used to estimate economic lives. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Diamondback's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease."

Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and 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 individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves prepared by Diamondback for the properties that we reviewed were estimated by performance methods, analogy, or a combination of methods. In general, the reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through December, 2025 in those cases where such data were considered to be definitive. The data used in these analyses were furnished to Ryder Scott by Diamondback or obtained from public data sources and were considered sufficient for the purpose thereof. In certain cases, producing reserves were estimated by analogy or a combination of methods. These methods were 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 estimates was considered to be inappropriate.

The reserves prepared by Diamondback attributable to the undeveloped status category that we reviewed were estimated by analogy.

To estimate economically producible proved oil and gas reserves and related future net cash flows, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Diamondback relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Diamondback for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2025 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Diamondback for the geographic area reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used by Diamondback to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by Diamondback were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback.

The table below summarizes Diamondback’s net volume weighted benchmark prices adjusted for differentials for the Viper properties reviewed by us and referred to herein as “average realized prices.” The average realized prices shown in the table below were determined from Diamondback’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and Diamondback’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$65.34/Bbl	$64.80/Bbl
	NGLs	WTI Cushing	$65.34/Bbl	$18.95/Bbl
	Gas	Henry Hub	$3.387/MMBTU	$1.31/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Diamondback’s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Because Viper is a royalty interest owner, no operating, development, or abandonment costs are shown in the detailed cash flow. However, these costs were incorporated into the economic evaluation to determine the commercially recoverable reserves reported herein.

Operating costs furnished by Diamondback are based on the operating expense reports of Diamondback and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by Diamondback were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Diamondback are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Diamondback were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback.

The proved undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Diamondback's plans to develop these reserves as of December 31, 2025 or based on timing received directly from outside operators which they believe to be reasonable and accurate due to the joint operational partnerships between Diamondback and the respective operators in each of these areas. The implementation of Diamondback's development plans as presented to us is subject to the approval process adopted by Diamondback's management. As the result of our inquiries during the course of our review, Diamondback has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Diamondback's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Diamondback. Diamondback has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Diamondback has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2025, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Diamondback were held constant throughout the life of the properties.

Diamondback's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were based on analog well performance and type-curves where appropriate. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Diamondback to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Diamondback. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Diamondback's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Diamondback's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Viper owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Diamondback for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Diamondback are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Diamondback has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Diamondback's forecast of future proved production and income, we have relied upon data furnished by Diamondback with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, certain abandonment costs, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Diamondback. We consider the factual data furnished to us by Diamondback to be appropriate and sufficient for the purpose of our review of Diamondback's estimates of reserves and future net income. In summary, we consider the assumptions, data, methods and analytical procedures used by Diamondback and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Diamondback, it is our opinion that the overall procedures and methodologies utilized by Diamondback in preparing estimates of Viper's proved reserves, future production and discounted future net income as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves, future production and discounted future net income for the reviewed properties as estimated by Diamondback are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Diamondback in their estimation of Viper's proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Diamondback's estimates of Viper's proved reserves, future production and discounted future net income for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Diamondback's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Diamondback when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves, future production and discounted future net income owned by Viper.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Diamondback and Viper. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Diamondback.

Diamondback makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Diamondback has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 of Diamondback, of the references to our name, as well as to the references to our third party report for Diamondback, which appears in the December 31, 2025 annual report on Form 10-K of Diamondback. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Diamondback.

We have provided Diamondback with a digital version of the original signed copy retained in our files. In the event there are any differences between the digital version included in filings made by Diamondback and the original signed copy in our files, the original signed file copy shall control and supersede.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Marsha E. Wellmann

Marsha E. Wellmann, P.E.
TBPELS License No. 116149
Managing Senior Vice President

[SEAL]

/s/ Raza Rizvi

Raza Rizvi
Senior Petroleum Engineer

/s/ James Wells

James Wells
Senior Petroleum Engineer

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Ms. Marsha E. Wellmann was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Ms. Wellmann, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2012, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies throughout North America and the Gulf of Mexico. Before joining Ryder Scott, Ms. Wellmann served in a number of engineering positions. For more information regarding Ms. Wellmann geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Ms. Wellmann earned a Bachelor of Science degree in Petroleum Engineering and a Business Foundations Certificate from The University of Texas at Austin in 2002 and is a registered Professional Engineer in the State of Texas. She is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Ms. Wellmann fulfills. As part of her 2025 continuing education hours, Ms. Wellmann attended 29 hours of formalized training including various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on her educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Ms. Wellmann has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.