CHESAPEAKE ENERGY

2023 ANNUAL REPORT

Answering the Call for Affordable, Reliable, Lower Carbon Energy

Dear Fellow Shareholders,

In 2024, the oil and natural gas industry continues to face challenges. Today's market remains oversupplied, with production peaking in late 2023 following significant capital expenditures in response to the pandemic's low investment cycle and Russia's invasion of Ukraine. In addition, this past winter's milder temperatures brought low heating demand, leaving natural gas storage levels 40% above their five-year averages.

Chesapeake was built for this moment. While market dynamics are resulting in cyclical lows for natural gas prices, demand is expected to rise materially over the next several years. In the U.S., growing markets of data centers and AI tools are requiring more electricity, and power generators are increasingly looking to natural gas to supply the base load. Globally, the U.S. is preparing to connect its natural gas production to underserved markets by building liquefied natural gas (LNG) terminals, of which nearly 12 bcf/d is currently under construction.

Our pending merger with Southwestern Energy will create a substantial opportunity to respond to evolving market dynamics and help connect crucial natural gas resources to consumers in need.

We will have an unparalleled U.S. natural gas portfolio — an investment grade-quality company with expansive access to premium markets and the ability to seamlessly move capital and best operating practices across basins.

Simply put, our combined company will deliver more gas to more markets more efficiently. As we look to the future, together we will materially advance the strategic pillars defined by Chesapeake.

Strategic Pillars	Superior Capital Returns	Deep, Attractive Inventory	Premier Balance Sheet	Sustainability Leadership
Combined Performance	~$1.0B – $1.5B of per annum dividends at current strip	>5,000 pro forma gross locations across Appalachia and Haynesville	Accelerates path to Investment Grade rating and lowers cost of capital	100% RSG certified across all basins and production

Chesapeake comes into the merger from a position of strength. Our strategic actions over the last three years have built a more resilient company focused on shareholder value.

- **Acquisitions of Vine and Chief:** Consolidated key offset positions in Haynesville and Marcellus allowing cost reductions and efficient development of additional resources
- **Divestitures of Powder River Basin and Eagle Ford:** Exited assets with limited actionable inventory economic in today's market conditions; proceeds provided significant balance sheet strength and return to shareholders
- **Pausing Turn-in-Line (TIL) of New Wells (2024):** Leveraged financial strength to reduce natural gas sales volumes in oversupplied market; retaining capacity to sell when demand recovers

Targeting our two core assets in 2023, we delivered tangible results with bottom line impact — demonstrating the operational excellence which has come to define Chesapeake.

MARCELLUS	HAYNESVILLE
• Drilled 9 of the 10 longest laterals in our history in the basin • Improved well costs by 17% (1Q to 4Q) and increased our footage drilled per day by 40%	• Outpaced our peers (drilling performance) in the most difficult drilling environment in the Lower 48 • Benefited from improved gathering system hydraulics

Most importantly, we accomplished these operational milestones while improving our combined TRIR by 40%, to an industry-leading 0.14. We also continued to reduce our GHG emissions with a focus on methane, decreasing our methane emissions intensity by more than 80% compared to our 2020 baseline.[a] Our year-end 2023 methane emissions intensity was 0.015%, substantially below the industry standard of 0.20% (as defined by the Oil and Gas Climate Initiative).

We will bring this same commitment, strategy and decision-making to the new company, post-merger. We have the portfolio, balance sheet and demonstrated operational track record to continue driving capital efficiencies, maximizing returns and reducing risk. **Together, we will accelerate America's energy reach and fuel a more affordable, reliable and lower carbon future.**

We are motivated by this opportunity for you, our shareholders, and the consumers and communities who benefit from the quality of life provided by natural gas. Thank you for your investment and partnership.

Michael A. Wichterich
Chairman of the Board

Domenic J. "Nick" Dell'Osso, Jr.
President, Chief Executive Officer and Director

(a) Our baseline includes those assets we owned at YE 2020: Eagle Ford, legacy Haynesville, legacy Marcellus and Powder River Basin. Methane emissions intensity calculated as volume methane emissions / volume gross operated natural gas produced.

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, 2023

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

For the transition period from __________ to __________

Commission File No. 001-13726

CHESAPEAKE ENERGY

CHESAPEAKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6100 North Western Avenue, Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	(Zip Code)

(405) 848-8000

(Registrant’s telephone number, including area code)

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, $0.01 par value per share	CHK	The Nasdaq Stock Market LLC
Class A Warrants to purchase Common Stock	CHKEW	The Nasdaq Stock Market LLC
Class B Warrants to purchase Common Stock	CHKEZ	The Nasdaq Stock Market LLC
Class C Warrants to purchase Common Stock	CHKEL	The Nasdaq Stock Market LLC

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 ☒

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

The aggregate market value of our common stock held by non-affiliates on June 30, 2023 was approximately $7.6 billion. As of February 15, 2024, there were 130,794,770 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2024 Annual Meeting of Stockholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
FORM 10-K
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Definitions

Unless the context otherwise indicates, references to “us,” “we,” “our,” “ours,” “Chesapeake,” the “Company” and “Registrant” refer to Chesapeake Energy Corporation and its consolidated subsidiaries. All monetary values, other than per unit and per share amounts, are stated in millions of U.S. dollars unless otherwise specified. Certain reserves and production information was previously disclosed in a per barrel of oil equivalent, since the majority of our production profile consists of natural gas, we have converted this information, including prior periods, from a per barrel of oil equivalent, to a per one thousand cubic feet of natural gas equivalent, referred to, on such a converted basis, as per Mcfe. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K (this “Form 10-K” or this “report”):

“Adjusted Free Cash Flow” (a non-GAAP measure) means net cash provided by operating activities (GAAP) less cash capital expenditures and contributions to investments, adjusted to exclude certain items management believes affect the comparability of operating results.

“ASC” means Accounting Standards Codification.

“Backstop Commitment Agreement” means that certain Backstop Commitment Agreement, dated as of June 28, 2020, by and between Chesapeake and the Backstop Parties, as may be further amended, modified, or supplemented from time to time, in accordance with its terms.

“Backstop Parties” means the members of the FLLO Ad Hoc Group that are signatories to the Backstop Commitment Agreement and Franklin Advisers, Inc., as investment manager on behalf of certain funds and accounts.

“Bankruptcy Code” means Title 11 of the United States Code, 11 U.S.C. §§ 101–1532, as amended.

“Bankruptcy Court” means the United States Bankruptcy Court for the Southern District of Texas.

“Bbl” or “Bbls” means barrel or barrels.

“Bcf” means billion cubic feet.

“Bcfe” means billion cubic feet of natural gas equivalent.

“BLM” means the Bureau of Land Management.

“Chapter 11 Cases” means, when used with reference to a particular Debtor, the case pending for that Debtor under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court, and when used with reference to all the Debtors, the procedurally consolidated Chapter 11 cases pending for the Debtors in the Bankruptcy Court.

“Chief” means Chief E&D Holdings, LP.

“Class A Warrants” means warrants to purchase 10 percent of the New Common Stock (after giving effect to the Rights Offering, but subject to dilution by the Management Incentive Plan, the Class B Warrants, and the Class C Warrants), at an initial exercise price per share of $27.63. The Class A Warrants are exercisable from the Effective Date until February 9, 2026.

“Class B Warrants” means warrants to purchase 10 percent of the New Common Stock (after giving effect to the Rights Offering, but subject to dilution by the Management Incentive Plan and the Class C Warrants), at an initial exercise price per share of $32.13. The Class B Warrants are exercisable from the Effective Date until February 9, 2026.

“Class C Warrants” means warrants to purchase 10 percent of the New Common Stock (after giving effect to the Rights Offering, but subject to dilution by the Management Incentive Plan), at an initial exercise price per share of $36.18. The Class C Warrants are exercisable from the Effective Date until February 9, 2026.

“Completion” means the process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas, oil or natural gas liquids, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

“Confirmation Order” means the order confirming the Fifth Amended Joint Chapter 11 Plan of Reorganization of Chesapeake Energy Corporation and its Debtor Affiliates, Docket No. 2915, entered by the Bankruptcy Court on January 16, 2021.

“DD&A” means depreciation, depletion and amortization.

“Debtors” means the Company, together with all of its direct and indirect subsidiaries that have filed the Chapter 11 Cases.

“DEI” means diversity, equity and inclusion.

“Developed Acreage” means acres which are allocated or assignable to producing wells or wells capable of production.

“DIP Facility” means that certain debtor-in-possession financing facility documented pursuant to the DIP Documents and DIP Order.

“Dry Well” means a well found to be incapable of producing either natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

“Effective Date” means February 9, 2021.

“ESG” means environmental, social and governance.

“Exit Credit Facility” means the reserve-based credit facility available upon emergence from bankruptcy. In December 2022, we terminated the Exit Credit Facility.

“Exploratory Well” means a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

“FLLO Term Loan Facility” means the facility outstanding under the FLLO Term Loan Facility Credit Agreement.

“FLLO Term Loan Facility Credit Agreement” means that certain Term Loan Agreement, dated as of December 19, 2019 ((i) as supplemented by that certain Class A Term Loan Supplement, dated as of December 19, 2019 (as amended, restated or otherwise modified from time to time), by and among Chesapeake, as borrower, the Debtor guarantors party thereto, GLAS USA LLC, as administrative agent, and the lenders party thereto, and (ii) as further amended, restated, or otherwise modified from time to time), by and among Chesapeake, the Debtor guarantors party thereto, GLAS USA LLC, as administrative agent, and the lenders party thereto.

“Formation” means a succession of sedimentary beds that were deposited under the same general geologic conditions.

“Free Cash Flow” (a non-GAAP measure) means net cash provided by operating activities (GAAP) less cash capital expenditures.

“G&A” means general and administrative expenses.

“GAAP” means U.S. generally accepted accounting principles.

“General Unsecured Claim” means any Claim against any Debtor that is not otherwise paid in full during the Chapter 11 Cases pursuant to an order of the Bankruptcy Court and is not an Administrative Claim, a Priority Tax Claim, an Other Priority Claim, an Other Secured Claim, a Revolving Credit Facility Claim, a FLLO Term Loan Facility Claim, a Second Lien Notes Claim, an Unsecured Notes Claim, an Intercompany Claim, or a Section 510(b) Claim.

“Gross Acres or Gross Wells” means the total acres or wells, as the case may be, in which a working interest is owned.

"LTIP" means the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.

"LNG" means liquefied natural gas.

"Marcellus Acquisition" means Chesapeake's acquisition of Chief and associated non-operated interests held by affiliates of Radler and Tug Hill, which closed on March 9, 2022, with an effective date of January 1, 2022.

"MBbls" means thousand barrels.

"MMBbls" means million barrels.

"Mcf" means thousand cubic feet.

"Mcfe" means one thousand cubic feet of natural gas equivalent, with one barrel of oil or NGL converted to an equivalent volume of natural gas using the ratio of one barrel of oil or NGL to six Mcf of natural gas.

"MMcf" means million cubic feet.

"MMcfe" means million cubic feet of natural gas equivalent.

"Net Acres or Net Wells" means the sum of the fractional working interests owned in gross acres or gross wells.

"New Common Stock" means the single class of common stock issued by Reorganized Chesapeake on the Effective Date.

"New Credit Facility" means the reserve-based credit facility entered into on December 9, 2022.

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"OPEC+" means Organization of the Petroleum Exporting Countries Plus.

"Petition Date" means June 28, 2020, the date on which the Debtors commenced the Chapter 11 Cases.

"Plan" means the Fifth Amended Joint Chapter 11 Plan of Reorganization of Chesapeake Energy Corporation and its Debtor Affiliates, attached as Exhibit A to the Confirmation Order.

"Play" means a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential natural gas, oil and NGL reserves.

"Present Value of Estimated Future Net Revenues or PV-10 (non-GAAP)" means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average natural gas and oil price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

"Price Differential" means the difference in the price of natural gas, oil or NGL received at the sales point and the NYMEX price.

"Productive Well" means a well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

"Proved Developed Reserves" means reserves that can be expected to be recovered 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.

"Proved Properties" means properties with proved reserves.

“Proved Reserves” has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which states in part proved natural gas and oil reserves are those quantities of natural gas and oil, 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.

“Proved Undeveloped Reserves (PUDs)” means 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. Reserves on undrilled acreage are 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.

“Put Option Premium” means a nonrefundable aggregate fee of $60 million, which represents 10 percent of the Rights Offering Amount, payable to the Backstop Parties in accordance with, and subject to the terms of the Backstop Commitment Agreement based on their respective backstop commitment percentages at the time such payment is made.

“Radler” means Radler 2000 Limited Partnership.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“Rights Offering” means the New Common Stock rights offering for the Rights Offering Amount consummated by the Debtors on the Effective Date.

“SEC” means United States Securities and Exchange Commission.

“Second Lien Notes” means the 11.50% senior notes due 2025 issued by Chesapeake pursuant to the Second Lien Notes Indenture.

“Second Lien Notes Claim” means any Claim on account of the Second Lien Notes.

“SOFR” means a rate equal to the secured overnight financing rate as administered by the SOFR Administrator, the Federal Reserve Bank of New York (or a successor administrator of the secured overnight financing rate).

“Southwestern” means Southwestern Energy Company.

“Southwestern Merger” means Chesapeake’s planned merger with Southwestern, which, subject to satisfaction or waiver of certain closing conditions, including certain regulatory approvals, is targeted to close in the second quarter of 2024.

“Standardized Measure” means the discounted future net cash flows relating to proved reserves based on the means of the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average natural gas and oil price during the preceding 12-month period prior to the end of the current reporting period (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period). The standardized measure differs from the PV-10 measure only because the former includes the effects of estimated future income tax expenses.

“Tcf” means trillion cubic feet.

“Tcfe” means trillion cubic feet of natural gas equivalent.

“Tranche A Loans” means the fully revolving loans made under and on the terms set forth under the Exit Credit Facility which were partially funded on the Effective Date. The Tranche A Loans were repaid in full in connection with our entry into the New Credit Facility.

“Tranche B Loans” means term loans made under and on the terms set forth under the Exit Credit Facility which were fully funded on the Effective Date. The Tranche B Loans were repaid in full in connection with our entry into the New Credit Facility.

“Tug Hill” means Tug Hill, Inc.

“Undeveloped Acreage” means acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of natural gas and oil regardless of whether the acreage contains proved reserves.

“Unproved Properties” means properties with no proved reserves.

“Vine” means Vine Energy Inc.

“Vine Acquisition” means Chesapeake’s acquisition of Vine, which closed on November 1, 2021.

“Warrants” means, collectively, the Class A Warrants, Class B Warrants and Class C Warrants.

“Working Interest” means the operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

“WTI” means West Texas Intermediate.

“/Bbl” means per barrel.

“/Mcf” means per Mcf.

“/Mcfe” means per Mcfe.

“2021 Predecessor Period” means the period of January 1, 2021 through February 9, 2021.

“2021 Successor Period” means the period of February 10, 2021 through December 31, 2021.

“2022 Successor Period” means the year ended December 31, 2022.

“2023 Successor Period” means the year ended December 31, 2023.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). Forward-looking statements include our current expectations or forecasts of future events, including matters relating to the pending Southwestern Merger, armed conflict and instability in Europe and the Middle East, along with the effects of the current global economic environment, and the impact of each on our business, financial condition, results of operations and cash flows, actions by, or disputes among or between, members of OPEC+ and other foreign oil-exporting countries, market factors, market prices, our ability to meet debt service requirements, our ability to continue to pay cash dividends, the amount and timing of any cash dividends and our ESG initiatives. Forward-looking and other statements in this Form 10-K regarding our environmental, social and other sustainability plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the SEC. In addition, historical, current, and forward-looking environmental, social and sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future. Forward-looking statements often address our expected future business, financial performance and financial condition, and often contain words such as "expect," “could,” “may,” "anticipate," "intend," "plan," “ability,” "believe," "seek," "see," "will," "would," “estimate,” “forecast,” "target," “guidance,” “outlook,” “opportunity” or “strategy.”

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- conservation measures and technological advances could reduce demand for natural gas and oil;
- negative public perceptions of our industry;
- competition in the natural gas and oil exploration and production industry;
- the volatility of natural gas, oil and NGL prices, which are affected by general economic and business conditions, as well as increased demand for (and availability of) alternative fuels and electric vehicles;
- risks from regional epidemics or pandemics and related economic turmoil, including supply chain constraints;
- write-downs of our natural gas and oil asset carrying values due to low commodity prices;
- significant capital expenditures are required to replace our reserves and conduct our business;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- drilling and operating risks and resulting liabilities;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- risks from our commodity price risk management activities;
- uncertainties, risks and costs associated with natural gas and oil operations;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- pipeline and gathering system capacity constraints and transportation interruptions;

- our plans to participate in the LNG export industry;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- risks from failure to protect personal information and data and compliance with data privacy and security laws and regulations;
- disruption of our business by natural or human causes beyond our control;
- a deterioration in general economic, business or industry conditions;
- the impact of inflation and commodity price volatility, including as a result of armed conflict and instability in Europe and the Middle East, along with the effects of the current global economic environment, on our business, financial condition, employees, contractors, vendors and the global demand for natural gas and oil and on U.S. and global financial markets;
- our inability to access the capital markets on favorable terms;
- the limitations on our financial flexibility due to our level of indebtedness and restrictive covenants from our indebtedness;
- our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information;
- risks related to acquisitions or dispositions, or potential acquisitions or dispositions, including risks related to the pending Southwestern Merger, such as the occurrence of any event, change or other circumstances that could give rise to the termination of the merger agreement for the Southwestern Merger; the possibility that our stockholders may not approve the issuance of our common stock in connection with the proposed transaction; the possibility that the stockholders of Southwestern may not approve the merger agreement; the risk that we or Southwestern may be unable to obtain governmental and regulatory approvals required for the proposed transaction, or required governmental and regulatory approvals may delay the Southwestern Merger or result in the imposition of conditions that could cause the parties to abandon the Southwestern Merger; the risk that the parties may not be able to satisfy the conditions to the proposed transaction in a timely manner or at all; risks related to limitation on our ability to pursue alternatives to the Southwestern Merger; risks related to change in control or other provisions in certain agreements that may be triggered upon completion of the Southwestern Merger; risks related to the merger agreement's restrictions on business activities prior to the effective time of the Southwestern Merger; risks related to loss of management personnel, other key employees, customers, suppliers, vendors, landlords, joint venture partners and other business partners following the Southwestern Merger; risks related to disruption of management time from ongoing business operations due to the proposed transaction; the risk that any announcements relating to the proposed transaction could have adverse effects on the market price of our common stock or Southwestern's common stock; the risk of any unexpected costs or expenses resulting from the proposed transaction; the risk of any litigation relating to the proposed transaction; the risk that problems may arise in successfully integrating the businesses of the companies, which may result in the combined company not operating as effectively and efficiently as expected; and the risk that the combined company may be unable to achieve synergies or other anticipated benefits of the proposed transaction or it may take longer than expected to achieve those synergies or benefits;
- our ability to achieve and maintain ESG certifications, goals and commitments;
- legislative, regulatory and ESG initiatives, addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal;

- federal and state tax proposals affecting our industry;
- risks related to an annual limitation on the utilization of our tax attributes, which is expected to be triggered upon the completion of the Southwestern Merger, as well as trading in our New Common Stock, additional issuance of New Common Stock, and certain other stock transactions, which could lead to an additional, potentially more restrictive, annual limitation; and
- other factors that are described under *Risk Factors* in Item 1A of Part I of this Form 10-K.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures in this report and our other filings with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

PART I

ITEM 1. Business

Unless the context otherwise requires, references to “Chesapeake,” the “Company,” “us,” “we” and “our” in this report are to Chesapeake Energy Corporation together with its subsidiaries. Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, and our main telephone number at that location is (405) 848-8000.

Our Business

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties to produce natural gas, oil and NGL from underground reservoirs. We own a large portfolio of onshore U.S. unconventional natural gas assets, including interests in approximately 5,000 gross natural gas wells.

On January 10, 2024, Chesapeake and Southwestern entered into an all-stock merger agreement. Southwestern is an independent energy company engaged in development, exploration and production activities, including related marketing activities, within its operating areas in the Marcellus and Haynesville shale plays. Pursuant to the terms of the merger agreement, at the effective time of the Southwestern Merger, each eligible share of Southwestern common stock issued and outstanding immediately prior to the effective time will be automatically converted into the right to receive 0.0867 of a share of Chesapeake’s common stock. Our Board of Directors and the Board of Directors of Southwestern both approved the merger agreement. Subject to the approval of our shareholders and Southwestern shareholders, regulatory approvals and the satisfaction or waiver of other customary closing conditions, the Southwestern Merger is targeted to close in the second quarter of 2024.

During 2023, we completed our exit from Eagle Ford through three separate divestiture transactions, with aggregate proceeds from these transactions exceeding $3.5 billion, subject to customary post-closing adjustments.

On March 25, 2022, we sold our Powder River Basin assets in Wyoming to Continental Resources, Inc. for approximately $450 million.

On March 9, 2022, we completed our acquisition of Chief, Radler and associated non-operated interests held by affiliates of Tug Hill. Chief, Radler and Tug Hill held producing assets and an inventory of premium drilling locations in the Marcellus Shale in Northeast Pennsylvania.

On November 1, 2021, we completed our acquisition of Vine, an energy company focused on the development of natural gas properties in stacked Haynesville and Mid-Bossier shale plays in Northwest Louisiana.

On June 28, 2020, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Bankruptcy Court confirmed the Plan in a bench ruling on January 13, 2021 and entered the Confirmation Order on January 16, 2021. The Debtors emerged from bankruptcy on February 9, 2021. Upon emergence, all existing equity was canceled and New Common Stock was issued to the previous holders of our FLLO Term Loan Facility, Second Lien Notes, senior unsecured notes and certain general unsecured creditors whose claims were impaired as a result of our bankruptcy, as well as to other parties as set forth in the Plan, including to other parties participating in a $600 million rights offering. Upon emergence from bankruptcy, we adopted fresh start accounting, which resulted in us becoming a new entity for financial reporting purposes. Accordingly, the consolidated financial statements on or after February 9, 2021 are not comparable to the consolidated financial statements prior to that date. To facilitate our discussion in this report, we refer to the post-emergence reorganized company as the “Successor” and the pre-emergence company as the “Predecessor.” See Note 2 and Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of our bankruptcy, the resulting reorganization and fresh start accounting.

Information About Us

We make available, free of charge on our website at *chk.com,* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent news releases. Documents and information on our website are not incorporated by reference herein.

The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Chesapeake, that file electronically with the SEC.

Business Strategy

Our business strategy is to create shareholder value through the responsible development of our significant resource plays, while continuing to be a leading provider of affordable, reliable, lower carbon energy to markets in need.

Superior Capital Returns. We consistently focus on optimizing the development of our large resource base with a prioritization of generating high cash returns on capital invested. Our drive toward continuous improvement through engineering innovation and planning enhances margins for our shareholders.

Deep, Attractive Inventory. We hold leading positions in each of the two premier natural gas fields in the U.S. offering premium rock, returns and runway. Our prioritization of best-in-class execution further unlocks these resources to the benefit of our stakeholders.

Sustainability Leadership. We are committed to protecting our country's natural resources and reducing our environmental footprint. We continue to foster a focus on environmental excellence through a culture of stewardship and sustainability among our employees and business partners. We recognize that ownership and accountability are key to helping ensure our work sites are safe and protective of the environment.

Premier Balance Sheet. We believe that maintaining low net leverage is integral to our business strategy and will allow us to maintain lower fixed costs, improve our margins and maintain the flexibility of our capital program. We further de-risk our margins and cash flows with prudent natural gas hedging that aims to reduce the impact of volatility.

Operating Areas

We focus our acquisition, exploration, development and production efforts in the geographic operating areas described below.

Marcellus - Northern Appalachian Basin in Pennsylvania.

Haynesville - Haynesville/Bossier Shales in Northwestern Louisiana.

Well Data

As of December 31, 2023, we held an interest in approximately 5,000 gross productive gas wells, including 3,300 (1,900 net) wells in which we held a working interest and 1,700 wells in which we held an overriding or royalty interest. Of the 3,300 wells in which we held a working interest, we operated 2,800 gross wells and held a non-operating working interest in 500 gross wells. We also completed 166 gross (108 net) wells as operator and participated in another 28 gross (1 net) wells completed by other operators. We operate approximately 98% of our current daily production volumes.

Drilling Activity

The following table sets forth the wells we completed or participated in during the periods indicated. In the table, "gross" refers to the total wells in which we had a working interest and "net" refers to gross wells multiplied by our working interest:

	2023				2022				2021			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	194	100	109	100	237	100	151	100	137	100	74	100
Dry	—	—	—	—	—	—	—	—	—	—	—	—
Total	194	100	109	100	237	100	151	100	137	100	74	100
Exploratory:												
Productive	—	—	—	—	—	—	—	—	2	100	1	100
Dry	—	—	—	—	1	100	1	100	—	—	—	—
Total	—	—	—	—	1	100	1	100	2	100	1	100

The following table shows the wells we completed or participated in by operating area:

	2023		2022		2021	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Marcellus	78	37	103	59	83	34
Haynesville	84	51	83	61	40	31
Eagle Ford	32	21	52	32	12	7
Powder River Basin	—	—	—	—	4	3
Total	194	109	238	152	139	75

As of December 31, 2023, we had 92 gross (58 net) wells in the process of being drilled or completed.

Production Volumes, Sales Prices, Production Expenses and Gathering, Processing and Transportation Expenses

The following tables present information regarding our net production volumes, average sales price received for our production, and production and gathering, processing and transportation expenses per Mcfe for the periods indicated for our significant fields:

	Production			
	Natural Gas (Bcf)	Oil (MMBbl)	NGL (MMBbl)	Total (Bcfe)
2023 Successor Period				
Marcellus	669	—	—	669
Haynesville	566	—	—	566
Eagle Ford	31	7.7	3.8	100
Total Production	1,266	7.7	3.8	1,335
2022 Successor Period				
Marcellus	670	—	—	670
Haynesville	588	—	—	588
Eagle Ford	46	18.7	5.8	193
Total Production	1,308	19.4	6.0	1,461
2021 Successor Period				
Marcellus	421	—	—	421
Haynesville	243	—	—	243
Eagle Ford	44	19.5	6.0	198
Total Production	727	22.5	7.1	905
2021 Predecessor Period				
Marcellus	50	—	—	50
Haynesville	22	—	—	22
Eagle Ford	7	3.0	0.7	29
Total Production	80	3.4	0.9	105

	Average Sales Price of Production[a]				Expenses ($/Mcfe)	
	Natural Gas ($/Mcf)	Oil ($/Bbl)	NGL ($/Bbl)	Total ($/Mcfe)	Production	GP&T
2023 Successor Period						
Marcellus	$ 2.22	$ —	$ —	$ 2.22	$ 0.12	$ 0.65
Haynesville	$ 2.30	$ —	$ —	$ 2.30	$ 0.33	$ 0.46
Eagle Ford	$ 2.25	$ 77.80	$ 25.62	$ 7.64	$ 0.91	$ 1.57
Total	$ 2.25	$ 77.80	$ 25.62	$ 2.66	$ 0.27	$ 0.64
2022 Successor Period						
Marcellus	$ 6.03	$ —	$ —	$ 6.03	$ 0.11	$ 0.57
Haynesville	$ 5.92	$ —	$ —	$ 5.92	$ 0.26	$ 0.53
Eagle Ford	$ 5.64	$ 96.10	$ 36.76	$ 11.76	$ 1.22	$ 1.78
Total	$ 5.96	$ 96.07	$ 37.48	$ 6.77	$ 0.33	$ 0.73
2021 Successor Period						
Marcellus	$ 3.25	$ —	$ —	$ 3.25	$ 0.08	$ 0.68
Haynesville	$ 4.10	$ —	$ —	$ 4.10	$ 0.24	$ 0.49
Eagle Ford	$ 4.02	$ 69.25	$ 29.76	$ 8.65	$ 0.88	$ 1.46
Total	$ 3.61	$ 69.07	$ 31.37	$ 4.87	$ 0.33	$ 0.86
2021 Predecessor Period						
Marcellus	$ 2.42	$ —	$ —	$ 2.42	$ 0.08	$ 0.70
Haynesville	$ 2.44	$ —	$ —	$ 2.44	$ 0.19	$ 0.49
Eagle Ford	$ 2.57	$ 53.37	$ 23.94	$ 6.71	$ 0.71	$ 1.55
Total	$ 2.45	$ 53.21	$ 25.92	$ 3.77	$ 0.30	$ 0.96

(a) Excludes the effect of hedging.

Natural Gas, Oil and NGL Reserves

The tables below set forth information as of December 31, 2023, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value of estimated future net revenue and the standardized measure of discounted future net cash flows. None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated natural gas, oil and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2023			
	Natural Gas	Oil	NGL	Total
	(Bcf)	(MMBbl)	(MMBbl)	(Bcfe)
Proved developed	6,363	—	—	6,363
Proved undeveloped	3,325	—	—	3,325
Total proved[a]	9,688	—	—	9,688

	Proved Developed	Proved Undeveloped	Total Proved
Standardized measure[b]			$ 4,477
Estimated future net revenue[b]	$ 6,194	$ 2,360	$ 8,554
Present value of estimated future net revenue (PV-10)[b]	$ 3,728	$ 843	$ 4,571

(a) Marcellus and Haynesville accounted for approximately 73% and 27%, respectively, of our estimated proved reserves by volume as of December 31, 2023.

(b) Estimated future net revenue represents the estimated future revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using pricing differentials and costs under existing economic conditions as of December 31, 2023, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2023. The price used in our PV-10 measure was $2.64 per Mcf of natural gas, before basis differential adjustments. This price should not be interpreted as a prediction of future prices, nor does it reflect the value of our commodity derivative instruments in place as of December 31, 2023. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense of $94 million as of December 31, 2023.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10, a non-GAAP measure, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A comparison of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved natural gas and oil reserves.

As of December 31, 2023, our proved reserve estimates included 3,325 Bcfe of reserves classified as proved undeveloped, compared to 4,321 Bcfe as of December 31, 2022. Presented below is a summary of changes in our proved undeveloped reserves for 2023:

	Total (Bcfe)
Proved undeveloped reserves, beginning of period	4,321
Extensions and discoveries	301
Revisions of previous estimates	236
Conversion to proved developed reserves	(1,125)
Purchase of reserves-in-place	40
Sales of reserves-in-place	(448)
Proved undeveloped reserves, end of period	3,325

As of December 31, 2023, all PUDs were planned to be developed within five years of original recording. In 2023, we invested approximately $674 million to convert 1,125 Bcfe of PUDs to proved developed reserves. We added 301 Bcfe of PUD reserves through extensions and discoveries primarily due to new PUDs added in the Upper Marcellus. We had a net upward revision in previous estimates of 236 Bcfe. The net upward revision primarily consisted of 1,345 Bcfe from PUDs added in areas previously categorized as proved in both Marcellus and Haynesville, and 469 Bcfe of positive revisions on existing PUD locations primarily related to longer expected lateral lengths in both Marcellus and Haynesville, partially offset by 1,131 Bcfe of downward revisions due to lower natural gas, oil and NGL prices in 2023, and a downward revision of 447 Bcfe due to development plan and other changes in Marcellus and Haynesville. We added 40 Bcfe of PUDs through purchase of reserves-in-place in Haynesville. We divested 448 Bcfe of PUD reserves primarily related to our Eagle Ford divestitures.

The future net revenue attributable to our estimated PUDs was $2.36 billion, and the present value was $843 million as of December 31, 2023. These values were calculated assuming that we will expend approximately $2.0 billion to develop these reserves ($649 million in 2024, $326 million in 2025, $463 million in 2026, $292 million in 2027 and $221 million in 2028). The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, commodity prices and the availability of capital. Our developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as commodity prices, unexpected developmental drilling results, title issues and infrastructure availability or constraints.

As of December 31, 2023, approximately 222 Bcfe, or 2%, of our total proved reserves were non-producing.

Our ownership interest used for calculating proved reserves and the associated estimated future net revenue assumes maximum participation by other parties to our farm-out and participation agreements.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2023, 2022 and 2021, along with the changes in quantities and standardized measure of the reserves for each of the three years then ended, are shown in *Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities* included in Item 8 of Part II of this report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured exactly, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. Accordingly, reserve estimates often differ from the actual quantities of natural gas, oil and NGL that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. See *Supplemental Disclosures About Natural Gas,* *Oil and NGL Producing Activities* included in Item 8 of Part II of this report for further discussion of our reserve quantities.

Reserves Estimation

We engaged Netherland, Sewell & Associates, Inc., a third-party engineering firm, to audit our total proved reserves as of December 31, 2023. A copy of the audit letter issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical persons at the firm primarily responsible for overseeing the audit of our reserve estimates are set forth below.

- Over 43 combined years of practical experience in the estimation and evaluation of reserves;
- Licensed Professional Engineer in the State of Texas and Bachelor of Science degree in Chemical Engineering/Engineering and Public Policy;
- Licensed Professional Geoscientist in the State of Texas and Bachelor of Science and Master of Science degrees in Geology.

Our Corporate Reserves Department prepared our estimated proved reserves as of December 31, 2023 disclosed in this report. Those estimates were established utilizing standard geological and engineering technologies, which are generally accepted by the petroleum industry and were based upon the best available production, engineering and geologic data. These technologies, including computational methods, provide reasonable certainty in our reserves estimation and include technologies and inputs such as drilling results and well performance, decline curve analysis of wells in analogous reservoirs, material balance, volumetric calculation, statistical analysis, well logs, geologic maps and seismic data.

Our Manager – SEC Reserves Engineering, who is in charge of our Corporate Reserves Department, is the technical person primarily responsible for overseeing the preparation of our reserve estimates and for coordinating any reserves work conducted by a third-party engineering firm. His qualifications include the following:

- Over 16 years of practical experience in the oil and gas industry, with over 14 years in reservoir engineering;
- Licensed Professional Engineer (Petroleum) in the State of Oklahoma;
- Member in good standing of the Society of Petroleum Evaluation Engineers;
- Bachelor of Science in Mechanical Engineering; and
- Master’s of Business Administration.

We ensure that the key members of our Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserve estimates. Our engineering technicians have a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field. We maintain a continuous education program for our engineers and technicians on new technologies and industry advancements as well as refresher training on basic skills and analytical techniques.

We maintain internal controls such as the following to ensure the reliability of reserves estimations:

- We follow comprehensive SEC-compliant internal policies to estimate and report proved reserves. Reserve estimates are made by experienced reservoir engineers or under their direct supervision. All material changes are reviewed and approved by the Manager – SEC Reserves Engineering.
- The Corporate Reserves Department reviews our proved reserves at the close of each quarter.
- Each quarter, Reservoir Managers, the Manager – SEC Reserves Engineering, the Senior Resource Manager, the Vice Presidents of each operating area and the Vice President of Corporate and Strategic Planning review all significant reserves changes and all new proved undeveloped reserves additions.
- The Corporate Reserves Department reports independently of our operations.
- The five-year PUD development plan is reviewed and approved annually by the Manager – SEC Reserves Engineering, the Senior Resource Manager, and the Vice President of Corporate and Strategic Planning.

Acreage

The following table sets forth our gross and net developed and undeveloped natural gas and oil leasehold and fee mineral acreage as of December 31, 2023. Gross acres are the total number of acres in which we own a working interest. Net acres refer to gross acres multiplied by our fractional working interest.

	Developed Leasehold		Undeveloped Leasehold		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)					
Marcellus	576	337	182	152	758	489
Haynesville	354	322	100	59	454	381
Other[(a)]	313	293	1,351	1,276	1,664	1,569
Total	1,243	952	1,633	1,487	2,876	2,439

(a) Includes 1.2 million net acres retained in the 2016 divestiture of our Devonian Shale assets, in which we retained all rights below the base of the Kope formation.

Most of our leases have a three- to five-year primary term, and we manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our drilling to establish production in paying quantities in order to hold leases by production, timely exercising our contractual rights to pay delay rentals to extend the terms of leases we value, planning non-core divestitures to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. We do not anticipate any material lease expirations within the next three years.

Marketing

The principal function of our marketing operations is to provide natural gas, oil and NGL marketing services, including commodity price structuring, securing and negotiating of gathering, hauling, processing and transportation services, contract administration and nomination services for us and other interest owners in Chesapeake-operated wells. The marketing operations also provide other services for our exploration and production activities, including services to enhance the value of natural gas and oil production by aggregating volumes sold to various intermediary markets, end markets and pipelines. This aggregation allows us to attract larger, more creditworthy customers that in turn assist in maximizing the prices received.

Generally, our natural gas and NGL production are sold to purchasers under index contracts, percentage-of-index contracts, spot price contracts or percentage-of-proceeds contracts. Under our index and percentage-of-index contracts, the price we receive is tied to published indices. Under the terms of our percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Oil production is sold under short-to-long-term market-sensitive and spot price contracts.

We have entered into long-term gathering, processing, and transportation contracts with various parties that require us to deliver fixed, determinable quantities of production over specified periods of time. Certain of our contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. See Note 7 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of commitments.

As of December 31, 2023, we had delivery commitments for a total of approximately 3,100 Bcf over the next 10 years. These delivery commitments vary each year, and we expect to fulfill these commitments primarily with production from our proved developed reserves.

Major Customers

For the 2023 Successor Period, sales to Valero Energy Corporation and Shell Energy North America accounted for approximately 17% and 10%, respectively, of total revenues (before the effects of hedging). For the 2022 Successor Period, sales to Shell Energy North America and Valero Energy Corporation accounted for approximately 13% and 10%, respectively, of total revenues (before the effects of hedging). For the 2021 Successor Period, sales to Valero Energy Corporation and Energy Transfer Crude Marketing accounted for approximately 14% and 11%, respectively, of total revenues (before the effects of hedging). For the 2021 Predecessor Period, sales to Valero Energy Corporation accounted for approximately 19% of total revenues (before the effects of hedging). No other purchasers accounted for more than 10% of our total revenues during the 2023 Successor Period, 2022 Successor Period, 2021 Successor Period or 2021 Predecessor Period.

Competition

We compete with both major integrated and other independent natural gas and oil companies in all aspects of our business to explore, develop and operate our properties and market our production. Some of our competitors may have larger financial and other resources than us. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect demand for natural gas and oil production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of natural gas pipelines and other transportation facilities and overall economic conditions. We also face indirect competition from alternative energy sources, including wind, solar and electric power. We believe that our technological expertise, combined with our exploration, land, drilling and production capabilities and the experience of our management team, enables us to compete effectively.

Public Policy and Government Regulation

All of our operations are conducted onshore in the United States. Our industry is subject to a wide range of regulations, laws, rules, taxes, fees and other policy implementation actions that have been pervasive and are under constant review for amendment or expansion. Numerous government agencies have issued extensive regulations that are binding on our industry, some of which carry substantial penalties for failure to comply. These laws and regulations increase the cost of doing business. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. We actively monitor regulatory developments applicable to our industry in order to anticipate, design and implement required compliance activities and systems. The following are significant areas of government control and regulation affecting our operations.

Exploration and Production, Environmental, Health and Safety and Occupational Laws and Regulations

Our operations are subject to federal, tribal, state, and local laws and regulations. These laws and regulations relate to matters that include, but are not limited to, the following:

- reporting of workplace injuries and illnesses;
- industrial hygiene monitoring;
- worker protection and workplace safety;
- approval or permits to drill and to conduct operations;
- provision of financial assurances (such as bonds) covering drilling and well operations;
- calculation and disbursement of royalty payments and production taxes;
- seismic operations/data;

- location, drilling, cementing and casing of wells;
- well design and construction of pad and equipment;
- construction and operations activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species, their habitats, or sites of cultural significance;
- method of well completion and hydraulic fracturing;
- water withdrawal;
- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- emissions and discharges permitting;
- climate change;
- use, transportation, storage and disposal of fluids and materials incidental to natural gas and oil operations;
- surface usage, maintenance, monitoring and the restoration of properties associated with well pads, pipelines, impoundments and access roads;
- plugging and abandoning of wells; and
- transportation of production.

In November 2021, the Environmental Protection Agency (the “EPA”) proposed new regulations to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments. The EPA issued a supplemental proposed rule in November 2022 to update, strengthen and expand its November 2021 proposed rule. In December 2023, the EPA issued the final rule, which imposes more stringent requirements on the natural gas and oil industry, requiring all well sites and compressor stations to be routinely monitored for leaks and eliminating or minimizing emissions from common pieces of equipment used in oil and gas operations, such as process controllers, pumps, and storage tanks. Further, in May 2023, the Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (the “PHMSA”) issued a proposed rule that would require pipelines, underground natural gas storage facilities, and liquefied natural gas facilities to update leak detection and repair programs to require companies to use commercially available technologies to find and fix methane leaks from pipelines and other facilities. These rules and policy priorities may result in the development of additional regulations or changes to existing regulations, certain of which could negatively impact our financial position, results of operations and cash flows. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States’ emissions by 50-52% below 2005 levels by 2030. Although the national commitments in the Paris Agreement create no binding requirements on individual companies or facilities, they do provide indications of the current administration’s policy direction and the types of legislative and regulatory requirements—such as the EPA’s final methane and volatile organic compound rule—that may be needed to achieve those commitments. In November 2021, the international community gathered again in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change (“COP26”), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs. While there were limited announcements at COP27, which took place in November 2022 in Sharm-El Sheik, with respect to the reduction of fossil fuel use, there were negotiations on emissions reduction targets and reduction of fossil fuel use amongst the international community. Relatedly, the United States and European Union jointly announced the launch of the “Global Methane Pledge,” which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including “all feasible reductions” in the energy sector. Such discussions continued at COP28 in Dubai, which resulted in an agreement among 200 nations to take more decisive climate action, including commitments to reduce reliance on fossil fuels.

In January 2024, the Biden administration announced a temporary pause on the U.S. Department of Energy's ("DOE") review of pending applications for authorization to export LNG to non-Free Trade Agreement countries until the DOE updates its underlying analyses for such decisions using more current data to account for considerations like potential energy cost increases for consumers and manufacturers or the latest assessment of the impact of GHG emissions. The temporary pause is not expected to affect LNG exports that have already been authorized. While this pause may not directly impact our exploration, production, and development activities, it may affect the demand for our products, which could have a material adverse effect on our business and financial position and impact our future business strategy.

In addition, several states and geographic regions in the United States have also adopted legislation and regulations regarding climate change-related matters, and additional legislation or regulation by these states and regions, U.S. federal agencies, including the EPA, and/or international agreements to which the United States may become a party could result in increased compliance costs for us and our customers. Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, administrative, civil or criminal fines or penalties or injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. We consider the responsibility and costs of environmental protection and safety and health compliance fundamental parts of our business. To date, we have been able to plan for and comply with environmental, safety and health laws and regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, as well as the increasing number of climate-related commitments by capital providers, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and may continue to increase. For example, in addition to existing regulations from the EPA and similar agencies, the SEC has issued proposed rules that would mandate extensive disclosure of climate-related risks and other information. Additionally, in August 2023, the EPA issued a proposed rule that would amend the Petroleum and Natural Gas Systems source category of the EPA's Greenhouse Gas Reporting Program to include new requirements for certain types of methane release events and bring the EPA's Greenhouse Gas Reporting Program's requirements into alignment with the Methane Emissions and Waste Reduction Incentive Program. For more information, see Item *1A. Risk Factors - "We are subject to extensive governmental regulation, which can change and could adversely impact our business."* The SEC has also indicated plans to propose various other disclosure regulations, including regarding human capital and other ESG matters. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

Our operations also are subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from gas and oil wells, and the unitization or pooling of gas and oil properties. In the United States, some states allow the statutory pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop gas and oil properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of gas and oil we can produce from our wells and the number of wells or the locations at which we can drill. For further discussion, see Item *1A. Risk Factors - We are subject to extensive governmental regulation, which can change and could adversely impact our business.*

Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies have continued to assess the potential impacts of hydraulic fracturing, which could spur further action toward federal, state and/or local legislation and regulation. Further restrictions of hydraulic fracturing could make it difficult or impossible to conduct our drilling and completion operations, and thereby reduce the amount of natural gas, oil and NGL that we are ultimately able to produce from our properties.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered by the U.S. Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has increased its review in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, gas and oil measurement and royalty payment obligations for production from federal lands. On November 30, 2022, the BLM issued a proposed rule to reduce the release of methane from venting, flaring, and leaks during gas and oil production activities on Federal and Indian leases, exemplifying the Biden Administration's increased focus on the climate change impacts of federal projects, which could result in further changes to the federal gas and oil leasing program in the future. Restrictions surrounding onshore drilling and restrictions on the ability to obtain required permits could have a material adverse impact on our operations.

Permitting activities are also subject to frequent delays. Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit our ability to execute our drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of our permits, inability to obtain new permits and the imposition of fines and penalties.

For further discussion, see Item *1A. Risk Factors - Natural gas and oil operations are uncertain and involve substantial costs and risks.*

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the natural gas and oil industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time that may result in litigation.

Operating Hazards and Insurance

The natural gas and oil business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, we could incur legal defense costs and could suffer substantial losses 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 investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

We maintain a control of well insurance policy with a $50 million single well limit and a $100 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. We also carry a $300 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $50 million pollution liability insurance policy providing coverage for gradual pollution related risks and in excess of the general liability policy for sudden and accidental pollution risks. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks, and policy limits scale to our working interest percentage in certain situations. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

Facilities

We own an office complex in Oklahoma City and we own or lease various field offices in cities or towns in the areas where we conduct our operations.

Executive Officers

Domenic J. Dell'Osso, Jr., ***President, Chief Executive Officer and Director***

Domenic J. ("Nick") Dell'Osso, Jr., 47, has served as President and Chief Executive Officer since October 2021. Prior to being named as CEO, Mr. Dell'Osso served as our Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso served as our Vice President – Finance and Chief Financial Officer of our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010. Before joining Chesapeake, Mr. Dell'Osso was an energy investment banker with Jefferies & Co. from 2006 to 2008 and Banc of America Securities from 2004 to 2006. Mr. Dell'Osso graduated from Boston College in 1998 and from the University of Texas at Austin in 2003.

Mohit Singh, ***Executive Vice President and Chief Financial Officer***

Mohit Singh, 47, has served as Executive Vice President and Chief Financial Officer since December 2021. Prior to joining Chesapeake, Mr. Singh served for six years on the executive leadership team at BPX Energy, the United States onshore subsidiary of BP (NYSE: BP). He most recently led the M&A, corporate land and reserves functions, having previously served as Head of Business Development and Exploration and as Senior Vice President – North Business Unit. Prior to joining BPX, Mr. Singh worked as an investment banker focused on oil and gas transactions for RBC Capital Markets and Goldman Sachs. A chemical engineer by training, he began his career at Shell Exploration & Production Company where he held business planning, reservoir engineering and research engineering roles of increasing importance. Mr. Singh earned a PhD in Chemical Engineering from the University of Houston, an MBA from the University of Texas and a BTech in Chemical Engineering from the Indian Institute of Technology.

Joshua J. Viets, ***Executive Vice President and Chief Operating Officer***

Joshua J. ("Josh") Viets, 45, has served as Executive Vice President and Chief Operating Officer since February 2022. Prior to joining Chesapeake, Mr. Viets worked for 20 years in operational positions of increasing importance at ConocoPhillips Company (NYSE: COP). He most recently served as Vice President, Delaware Basin and previously held leadership positions in operations, engineering, subsurface, and capital project across the ConocoPhillips portfolio. Mr. Viets earned a Bachelor of Science in Petroleum Engineering from Colorado School of Mines in 2001.

Benjamin E. Russ, ***Executive Vice President - General Counsel and Corporate Secretary***

Benjamin E. ("Ben") Russ, 49, has served as Executive Vice President – General Counsel and Corporate Secretary since June 2021. Prior to that time, he served as Associate General Counsel – Corporate from May 2014 to June 2021; Division Counsel/Senior Division Counsel managing day-to-day legal matters in the Barnett, East Texas and Louisiana from July 2010 to May 2014; and Attorney/Senior Attorney managing litigation in Louisiana from September 2008 to July 2010. Before joining Chesapeake, Mr. Russ worked at Gulfport Energy Corporation serving as Assistant General Counsel from 2005 to 2006 and General Counsel from 2006 to 2008. Prior to Gulfport, he was an associate at the McKinney & Stringer, P.C. Mr. Russ received a B.S. in Finance from Oklahoma State University in 1996 and a J.D. from Oklahoma City University in 2004.

Human Capital Resources

One Team. One Chesapeake.

Our “One CHK” culture and company core values are aimed at promoting an inclusive, diverse and productive workplace. Working as One CHK defines Chesapeake’s culture and unites our team to achieve shared goals for the benefit of our stakeholders. It is a culture of accountability where innovation, collaboration and calculated risk-taking help us achieve sustainable operational success. We had approximately 1,000 employees as of December 31, 2023. None of our employees were covered by collective bargaining agreements, and our management works to maintain good relations with our employees.

Our Culture, Our Core Values

At Chesapeake, our employees are driven to create value every day in a safe and responsible manner. Our core values are the foundation of our culture and the driving force behind our goal to achieve ESG excellence. Serving as the lens through which we evaluate every business decision, our commitment to these values, in both words and actions builds a stronger, healthier Chesapeake, benefiting all our stakeholders. Our core values are:

- Integrity and Trust
- Respect
- Transparency and Open Communication
- Commercial Focus
- Change Leadership

Celebrating Diversity, Equity and Inclusion

We are committed to inclusion and diversity. Building a diverse workforce and equitable and inclusive work culture is an important factor in contributing to Chesapeake’s sustainable success. We proactively embrace our diversity of people, thoughts and talents, and combine these strengths to pursue results and meaningful change for our company, employees and stakeholders, and we provide education and training for our employees on topics related to inclusion and diversity.

In 2019, Chesapeake joined a coalition of companies pledging to advance diversity and inclusion in the workplace. On February 9, 2021, we formed a board committee dedicated to ESG oversight, including our inclusion and diversity efforts. Two of the seven members of our Board of Directors are considered to come from underrepresented backgrounds, including one woman and one “underrepresented minority” (as defined in Nasdaq’s board diversity rule). Chesapeake cultivates a workplace in which diverse perspectives are welcomed and respected and where employees feel encouraged to discuss diversity and inclusion.

In 2022, we further advanced our DEI program by nominating an executive sponsor from the Company’s senior management team, along with our inaugural advisory board and council teams. Each of these branches of our DEI program take part in determining strategic priorities, advancing our culture and supporting internal activities that invite all employees to participate in achieving our DEI vision.

For all these reasons, we believe our DEI program helps contribute to our corporate culture and business performance. We also recognize the importance of these efforts being compliant with applicable laws. DEI efforts are part of our legal compliance considerations, and we are committed to not making employment decisions, including decisions regarding hiring, promotion, and compensation, on the basis of any legally protected characteristic, such as race or gender.

Stay Accident Free Everyday (S.A.F.E.)

Safety is more than a company metric. It is core to our commitment to leading a responsible energy future. We set and deliver robust safety standards, prioritizing the well-being of our employees and contractors. Our safety culture is championed by our Board of Directors and executive leadership team, owned by every employee and contractor and managed by our Health, Safety, Environmental and Regulatory (HSER) team. Maintaining a safe work environment and promoting safe behaviors is a commitment that each of our employees and contractors own together. We hold each other accountable to keeping our sites, our co-workers and our contractors safe.

One program that reinforces this philosophy of personal responsibility is Stop Work Authority. Through Stop Work Authority, every employee and contractor has the right, responsibility and authority to stop work if conditions are unsafe or could cause harm to the environment. Creating an incident-free work environment starts with setting clear expectations among employees and contractors regarding our Safe and Compliant Operations Policy, safety standards, and working to empower and equip individuals with the skills necessary to promote safety in their areas of work. The foundation of our safety training efforts is our Stay Accident Free Every day (S.A.F.E.) program, which encourages all workers on our locations to take personal responsibility for their safety and the safety of those around them. This behavior-based program addresses the activities that can often lead to safety incidents and encourages actions that create safe work sites and a safe corporate campus.

Every year our HSER team provides targeted trainings based on safety performance analysis, job functions and location specific factors. Our training program includes a mix of in-person and virtual training, with greater emphasis on in-person instruction and includes all employees. Job-specific learning paths aim to exceed regulatory requirements and ensure employees are holistically prepared to execute their job functions safely and responsibly.

Chesapeake's training philosophy values contractor training in the same manner as employees. We design contractor training to align as much as possible with employee training, encouraging synchronized knowledge sharing and understanding, critical to decreasing our cumulative incidents.

Ethical Business Conduct

Chesapeake works hard to maintain the confidence of our stakeholders. We earn this trust by striving to act in an ethical manner to protect our people, the environment and the communities where we operate. This starts by driving accountability through all levels of the company and having systems in place to uphold our high standards for conduct. Strong governance practices begin at the top providing our organization with clear guidelines to define standards for ethical behavior at every level. Each Chesapeake director or employee, regardless of position, must abide by Chesapeake's Code of Business Conduct (the "Code"), which is structured around our core values. Each year all employees must sign a Code certification confirming they have reviewed the Code and related policies, understand the high standards expected of them and will report actual or potential ethics concerns or Code violations.

Employee Wellness and Benefits

Supporting the individual well-being of our employees is foundational to our safety culture and success as a company. We champion healthy lifestyles and offer health resources. Across the company, employees are offered preventive programs and are encouraged to complete an annual screening for common health-related issues. We support our employees' and their families' health by offering full medical, dental, vision, prescription drug insurance for employees and their families, life insurance, short- and long-term disability coverage, and health savings and dependent care flexible spending accounts. We offer parental leave for the birth or adoption of a child, an adoption assistance program, alternate work schedules, a 401(k) savings plan with company match and discretionary contributions, flexible work hours, generous paid time off, including a well-being day, where each employee is encouraged to relax and recharge for a day once per calendar year and 12 company-paid holidays, tuition reimbursement and access to a child development center and fitness center at market rates. Additionally, Chesapeake provides employees and their families access to a confidential Employee Assistance Program, which connects employees with trained counselors and other support professionals.

Item 1A. *Risk Factors*

There are numerous factors that affect our business and results of operations, many of which are beyond our control. The following is a description of factors that we consider to be material and that might cause our future results to differ materially from those currently expected. The risks described below are not the only risks facing our company. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also affect our business operations. If any of these risks actually occur, our business, financial position, results of operations, cash flows, reserves and/or our ability to pay our debts and other liabilities could suffer, the trading price and liquidity of our securities could decline and you may lose all or part of your investment in our securities.

Summary Risk Factors

Risks Related to Operating our Business

- Conservation measures and technological advances could reduce demand for natural gas and oil.
- Negative public perception regarding us or our industry could have an adverse effect on our operations.
- Risks related to potential acquisitions or dispositions may adversely affect our business.
- The gas and oil exploration and production industry is very competitive;
- Natural gas, oil and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.
- Regional epidemics or pandemics and related economic turmoil, including supply chain constraints, have affected, and could in future adversely affect us.
- If commodity prices fall or drilling efforts are unsuccessful, we may be required to record write-downs of the carrying value of our natural gas and oil properties.
- Significant capital expenditures are required to replace our reserves and conduct our business.
- If we are not able to replace reserves, we may not be able to sustain production.
- The actual quantities of and future net revenues from our proved reserves may be less than our estimates.
- Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.
- Certain of our undeveloped properties are subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed.
- Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.
- Natural gas and oil operations are uncertain and involve substantial costs and risks.
- Our ability to produce natural gas, oil and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.
- Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.
- Our business strategy is increasingly focused on capitalizing on the growing U.S. LNG export market, a highly regulated and capital intensive industry with a number of inherent commercial risks. U.S. LNG exports have helped drive domestic demand for natural gas, and, as a natural-gas producer, we could be materially and adversely impacted by a deterioration in the U.S. LNG export industry, which could in turn reduce demand for natural gas. In addition, we may seek to more directly participate in the LNG market through direct marketing arrangements with LNG export facilities and/or end users, which could expose us to additional commercial risks associated with the global LNG markets.
- Cyber-attacks targeting systems and infrastructure used by the gas and oil industry and related regulations may adversely impact our operations and, if we or our third-party providers are unable to obtain and maintain adequate protection for our key systems and data, our business may be harmed.

- We collect, process, store and use personal information and other data, and our actual or perceived failure to protect such information and data or comply with data privacy and security laws and regulations could damage our reputation and brand and harm our business and operating results.
- Our operations could be disrupted by natural or human causes beyond our control.
- A deterioration in general economic, political, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.
- Military and other armed conflicts, including terrorist activities, and related price volatility and geopolitical instability could materially and adversely affect our business and results of operations.

Financial Risks Related to our Business

- We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by industry conditions.
- Restrictive covenants in certain of our debt agreements could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.
- Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the Plan and the transactions contemplated thereby.

Risks Related to the Southwestern Merger

- The Southwestern Merger may not be completed on the terms or timeline currently contemplated, or at all. Failure to complete or any delays in completing the Southwestern Merger could negatively impact the price of shares of our common stock, as well as our future business and financial results. Furthermore, the Southwestern Merger agreement subjects the Company to certain restrictions prior to the effective time of the Merger that could prevent the company from pursuing certain business opportunities.
- The synergies attributable to the Southwestern Merger, if consummated, may vary from expectations, and we will be subject to business uncertainties for a period of time after the closing of the Southwestern Merger, if consummated, which could adversely affect the combined company. These uncertainties could include, but may not be limited to, loss of key personnel, retention of customer or supplier contracts or relationships, incurrence of significant indebtedness, and litigation in connection with the Southwestern Merger.

Legal and Regulatory Risks

- We are subject to extensive governmental regulation, which can change and could adversely impact our business.
- Environmental matters and related costs can be significant.
- Increasing attention to ESG matters and our ability to achieve and maintain ESG certifications, goals and commitments may impact our business, financial results or stock price.
- The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business.
- The completion of the Southwestern Merger is anticipated to trigger an annual limitation on the utilization of our tax attributes, reducing their ability to offset future taxable income, which may result in an increase to income tax liabilities. In addition, trading in our New Common Stock, additional issuance of New Common Stock, and certain other stock transactions could lead to an additional, potentially more restrictive, annual limitation.

Risks Related to Operating our Business

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

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas and oil. The impact of the changing demand for natural gas and oil could adversely impact our earnings, cash flows and financial position.

Negative public perception regarding us or our industry could have an adverse effect on our operations.

Negative public perception regarding us or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to generally increased political pressure and regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, encourage capital providers to divest of their interests in us or our industry, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation, as well as potentially reducing our ability to execute routine or strategic business partnerships. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business. A change in control of national, state or local governments, including the U.S. presidential administration, Congress, state or local governments, and governments of other countries may also result in uncertainty regarding the degree to which there will be increased restrictions on natural gas and oil production activities, which could materially adversely affect our industry and our financial condition and results of operations.

Certain financial institutions, funds and other sources of capital have also elected to restrict or eliminate their investment in certain fossil fuel-related activities. Even if capital providers have not generally restricted their investment in fossil fuel-related activities, they may still assess various ESG considerations in making voting and capital allocation decisions. Responding to these and other stakeholder concerns on ESG matters may require us to incur additional costs or otherwise impact our business. For more information, see our risk factor *"Increasing attention to ESG matters and our ability to achieve and maintain ESG certifications, goals and commitments may impact our business, financial results or stock price."*

Risks related to potential acquisitions or dispositions may adversely affect our business.

From time to time, we evaluate acquisitions and dispositions of assets, businesses and other investments. These transactions may not result in the anticipated benefits or efficiencies. In addition, acquisitions may be financed by borrowings, requiring us to incur more debt, or by the issuance of our common stock. Any such acquisition or disposition involves risks and we cannot assure you that:

- any acquisition will be successfully integrated into our operations and internal controls;
- the due diligence conducted prior to an acquisition will uncover situations that could result in financial or legal exposure, such as title defects and potential environmental and other liabilities;
- post-closing purchase price adjustments will be realized in our favor;
- our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating expenses and costs will be accurate;
- there will not be delays in closing, lower than expected sales proceeds for the disposed assets or business, residual liabilities, or post-closing claims for indemnification;

- any investment, acquisition, or disposition will not divert management resources from the operation of our business; and
- any investment, acquisition, or disposition will not have a material adverse effect on our financial condition, results of operations, cash flows or reserves.

If any of these risks materialize, the benefits of such acquisition or disposition may not be fully realized, if at all, and our financial condition, results of operations, cash flows and reserves could be negatively impacted.

The gas and oil exploration and production industry is very competitive; some of our competitors have greater financial and other resources than we do, and there is competition to attract and retain talent and competition over access to certain industry equipment.

We face competition in every aspect of our business, including, but not limited to, buying and selling reserves and leases, obtaining goods and services needed to operate our business and marketing natural gas, oil or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address industry challenges more effectively or weather industry downturns more easily than we can. We also face indirect competition from alternative energy sources, including wind, solar and electric power.

Our performance depends largely on the talents and efforts of highly skilled individuals and on our ability to attract new employees and to retain and motivate our existing employees. Competition in our industry for qualified employees is intense. If we are unsuccessful in attracting and retaining skilled employees and managerial talent, our ability to compete effectively may be diminished. We also compete for the equipment required to explore, develop and operate properties. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield equipment and services, which could adversely affect our ability to execute our development plans on a timely basis and within budget.

Natural gas, oil and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

Our revenues, results of operations, profitability, liquidity, leverage ratio and ability to grow and invest in capital expenditures depend primarily upon the prices we receive for the natural gas, oil and NGL we sell. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low natural gas, oil and NGL prices can negatively affect the amount of cash available for capital expenditures, debt service and debt repayment and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves. In addition, periods of low natural gas and oil prices may result in a reduction of the carrying value of our natural gas and oil properties due to recognizing impairments in proved and unproved properties.

Volatility in natural gas, oil and NGL prices may result from factors that are beyond our control, including:

- domestic and worldwide supplies of natural gas, oil and NGL, including U.S. inventories of natural gas and oil reserves;
- weather conditions;
- changes in the level of consumer and industrial demand, including impacts from global or national health epidemics and concerns, such as the COVID-19 pandemic;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of natural gas, oil, liquefied natural gas and NGL;

- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and others to agree to and maintain oil price and production controls;
- increased use of competing energy products, including alternative energy sources;
- political instability or armed conflict in natural gas and oil producing regions, including in connection with the continued armed conflict and instability in Europe and the Middle East;
- acts of terrorism; and
- domestic and global economic and political conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements. In addition, any prolonged period of lower prices could reduce the quantities of reserves that we may economically produce.

Regional epidemics or pandemics and related economic turmoil, including supply chain constraints, have affected, and could in future adversely affect our business, financial condition, results of operations and cash flows.

The COVID-19 pandemic adversely impacted the entire global economy, including creating supply chain constraints, and any future regional epidemics or global pandemics and governmental and other measures implemented to try to address them, such as quarantines, shelter-in-place orders, business and government shutdowns and restrictions on operations, could adversely affect our business, financial condition, results of operations and cash flows. Actions by our customers and derivative contract counterparties in response to such events and their economic impacts, including potential non-performance or delays, could also have an adverse impact on our business.

If commodity prices fall or drilling efforts are unsuccessful, we may be required to record write-downs of the carrying value of our natural gas and oil properties.

We have been required to write down the carrying value of certain of our natural gas and oil properties in the past, and there is a risk that we will be required to take additional write-downs in the future. Write-downs may occur in the future when natural gas and oil prices are low for sustained periods, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, or due to the anticipated sale of properties.

The successful efforts method of accounting requires that we periodically review the carrying value of our natural gas and oil properties for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write-down the carrying value of a property based on natural gas and oil prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. A write-down constitutes a non-cash charge to earnings and does not impact cash or cash flows from operating activities; however, it reflects our long-term ability to recover an investment, reduces our reported earnings and increases certain leverage ratios. See *Impairments* within Critical Accounting Estimates included in Item 7 of this report for further information.

Significant capital expenditures are required to replace our reserves and conduct our business.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through cash flows from operations, and to the extent that is not sufficient, borrowings under our revolving credit facility. Our ability to generate operating cash flow is subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas, oil and NGL, our success in developing and producing new reserves and the other risk factors discussed herein. Our forecasted 2024 capital expenditures, inclusive of capitalized interest, are $1.25 - $1.35 billion compared to our 2023 capital spending level of $1.8 billion. Management continues to review operational plans for 2024 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of natural gas, oil and NGL. If we are unable to fund our capital expenditures as planned, we could experience a curtailment of our exploration and development activity, a loss of properties and a decline in our natural gas, oil and NGL reserves.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. Thus, our future natural gas and oil reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities of and future net revenues from our proved reserves may be less than our estimates.

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to natural gas, oil and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas, oil and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to future revisions.

Actual future production, natural gas, oil and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, oil and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

As of December 31, 2023, approximately 34% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans for capital expenditures to convert PUDs into proved developed reserves, including approximately $2.0 billion during the next five years. You should be aware that the estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not be as estimated. If we choose not to develop our PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them from our reported proved reserves. In addition, under the SEC’s reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average natural gas and oil price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2023 present value is based on the price of $2.64 per Mcf of natural gas, before basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect both the timing of future net cash flows from our proved reserves and their present value. Any changes in demand for natural gas and oil, governmental regulations or taxation will also affect the future net cash flows from our production. In addition, the 10% discount factor that is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the gas and oil industry in general will affect the appropriateness of the 10% discount factor.

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

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We have acquired undeveloped properties that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that undeveloped properties acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive, or that we will recover all or any portion of our investment in such undeveloped properties or wells.

Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling and completion operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, title problems, equipment failures or accidents, shortages of midstream transportation, equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and produced water disposal, federal restrictions on gas and oil leasing and permitting, and a decline in commodity prices, among others. The profitability of wells, particularly in certain of the areas in which we operate, will be reduced or eliminated if commodity prices decline. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas, oil and NGL, costs associated with producing natural gas, oil and NGL and our ability to add reserves at an acceptable cost.

We rely to a significant extent on seismic data and other technologies in evaluating undeveloped properties and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of undeveloped properties, or drilling a well, whether natural gas or oil is present or may be produced economically. If we incur significant expense in acquiring or developing properties that do not produce as expected or at profitable levels, it could have a material adverse effect on our results of operations and financial condition.

Certain of our undeveloped properties are subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed.

Leases on natural gas and oil properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases on our undeveloped properties expire and we are unable to renew the leases, we will lose our right to develop the related properties. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties.

Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

To manage our exposure to price volatility, we enter into natural gas, oil and NGL price derivative contracts. Our natural gas, oil and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our natural gas, oil and NGL derivative instruments can fluctuate significantly between periods. Our decision to mitigate cash flow volatility through derivative arrangements, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to enter into derivatives if we believe the pricing environment for certain time periods is unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities to monetize gain positions for the purpose of funding our capital program.

Most of our natural gas, oil and NGL derivative contracts are with counterparties under bilateral hedging arrangements. Under a majority of our arrangements, the collateral provided for our obligations is secured by the same hydrocarbon interests that secure our New Credit Facility. Our counterparties' obligations under the arrangements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us exceed defined thresholds. Collateral requirements are dependent to a large extent on natural gas and oil prices.

Natural gas, oil and NGL derivative transactions expose us to the risk that our counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, the value of our commodity derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our hedging arrangements are required to secure their obligations to us under certain scenarios, if any of our counterparties were to default on their obligations to us under the derivative contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future cash flows being exposed to commodity price changes.

Natural gas and oil operations are uncertain and involve substantial costs and risks.

Our operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive gas or oil reservoirs. Drilling for natural gas, oil and NGL can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop gas and oil properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. Although both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. In addition, our gas and oil properties can become damaged, our operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control;
- the mishandling or underground migration of fluids and chemicals;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures;
- issues with title or in receiving governmental permits or approvals;
- restricted takeaway capacity for our production, including due to inadequate midstream infrastructure or constrained downstream markets;
- environmental hazards or liabilities;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations;
- shortages or delays in the availability of services or delivery of equipment; and
- unexpected or unforeseen changes in regulatory policy, and political or public opinion.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities. Although we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, we have limited or no insurance coverage. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which we are not fully insured may expose us to liabilities.

Moreover, certain of these events could result in environmental pollution and impact to third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death, significant damage to property and natural resources, or significant financial liabilities or penalties.

Our ability to produce natural gas, oil and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Development activities, particularly hydraulic fracturing, require the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. The imposition of environmental initiatives and regulations could further restrict our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of natural gas and oil.

Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. We rely heavily on third parties to meet our natural gas, oil and NGL gathering needs. Capital constraints could limit the construction of new pipelines and gathering systems and the provision or expansion of trucking services by third parties. Until this new capacity is available, we may experience delays in producing and selling our natural gas, oil and NGL. In such event, we might have to shut in our wells while awaiting a pipeline connection or additional capacity, which would adversely affect our results of operations.

A portion of our natural gas, oil and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could materially adversely affect our cash flow.

Our business strategy is increasingly focused on capitalizing on the growing U.S. LNG export market, a highly regulated and capital intensive industry with a number of inherent commercial risks. U.S. LNG exports have helped drive domestic demand for natural gas, and, as a natural-gas producer, we could be materially and adversely impacted by a deterioration in the U.S. LNG export industry, which could in turn reduce demand for natural gas. In addition, we may seek to more directly participate in the LNG market through direct marketing arrangements with LNG export facilities and/or end users, which could expose us to additional commercial risks associated with the global LNG markets.

As a domestic natural gas exploration and production company, we may be indirectly exposed to certain risks in the U.S. LNG export markets, including to the extent that we have entered into, or may in the future enter into, long-term natural gas supply agreements with LNG export facilities. The LNG export industry is a highly regulated and capital intensive industry that is subject to a number of risks. Many facilities remain under construction or are expanding, and if these facilities are unable to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the design, construction and operation of their facilities, or if they are unable to secure financing in connection with their operations or the completion of their planned projects, the U.S. LNG market may be materially and adversely impacted, which could reduce demand for U.S. natural gas and have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We may also in the future enter into other commercial arrangements directly with foreign LNG customers. LNG sale and purchase agreements commonly have terms exceeding 10 years, which could expose us to credit risk should a customer default and we are required to seek recourse. Additionally, long-term LNG sales and purchase agreements generally permit a customer to terminate their contractual obligations upon the occurrence of certain events, including: (i) a failure to make available specified scheduled cargo quantities, (ii) delays in the commencement of commercial operations, and (iii) the occurrence of certain events of force majeure. The occurrence of these and other events permitting termination may be outside of our control and may expose us to unrecoverable losses.

Further, any future commercial agreement may expose us to commodity risks associated with differential pricing of natural gas in different markets. LNG and natural gas are traded according to prices determined with reference to a variety of international indices, including the Japan Korea Marker (JKM) and the Dutch TTF market, each of which may materially differ from prices that use the U.S. Henry Hub index as a reference price. If we are unable to manage the impacts of unfavorable price differentials between domestic and international indices for LNG or natural gas in the context of future agreements, this could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Cyber-attacks targeting systems and infrastructure used by the gas and oil industry and related regulations may adversely impact our operations and, if we or our third-party providers are unable to obtain and maintain adequate protection for our key systems and data, our business may be harmed.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of natural gas, oil and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. In addition, many third-party providers, such as vendors and others in the supply chain, directly or indirectly provide to us various products and services across an array of internal and external functions that enable us to conduct, monitor and/or protect our business, systems and data assets. In addition, in the ordinary course of business, we and our service providers collect, process, transmit, and store proprietary and confidential data, including personal information.

We have been the subject of cyber-attacks on our internal systems and through those of third parties in the past. As an energy company, we expect to continue to be a target for such attacks in the future from nation-state sponsored foreign actors and other attackers. We face evolving cybersecurity risks that threaten the confidentiality, integrity, and availability of our digital technologies and business data, including malicious attacks by third parties or insiders, social engineering/phishing and human error, as well as bugs, misconfigurations of hardware or software and other vulnerabilities that may exist in our or our third-party providers' systems or technologies. Unauthorized access to our seismic data, reserves information, customer or employee data or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operations. If our information technology systems cease to function properly or our cybersecurity is breached (for example, due to ransomware), we could suffer disruptions to our normal operations, which may include disruptions to our drilling, completion, production and corporate functions. There can also be no assurance that our cybersecurity risk management program and processes, including our policies, controls or procedures, will be fully implemented, complied with or effective in protecting our systems and data. A cyber-attack, or the perception thereof, involving our information systems and related infrastructure, or that of our business associates or third-party providers, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps. Additionally, failure to comply with the obligations of any cyber incident notification laws or regulations can result in legal claims or proceedings (such as class actions), regulatory investigations and enforcement actions, fines and penalties, and negative reputational impacts that could cause us to lose existing or future customers.

In the event of a cyber-attack, we may be required by federal and state laws or regulations to provide notification to regulators or individuals. For example, the Cyber Incident Reporting for Critical Infrastructure Act (CIRCIA) was signed into law on March 15, 2022. CIRCIA mandates that all owners and operators of critical infrastructure report cyber incidents to the U.S. Department of Homeland Security's Cybersecurity and Infrastructure Security Agency (CISA) within 72 hours and ransomware payments within 24 hours. These new requirements will become effective once CISA promulgates rules pursuant to the Act. CISA is required to issue a notice of proposed rulemaking by March 2024 and issue a final rule within 18 months of issuing the proposed rule.

Both the frequency and magnitude of cyberattacks is expected to increase as attackers are becoming more sophisticated. As a result, we may be unable to anticipate, detect, prevent, investigate or contain future attacks, particularly as the methodologies utilized by attackers change frequently or are not recognized until launched, and we may be unable to investigate or remediate incidents because attackers are increasingly using techniques and tools designed to circumvent controls, to avoid detection, and to remove or obfuscate forensic evidence. Further, global remote working dynamics for our customers, employees and third-party providers present additional risk that threat actors may seek to engage in social engineering (for example, phishing) and to exploit vulnerabilities in corporate and non-corporate networks. As cyber-attacks continue to evolve, we may be required to spend significant additional resources to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks.

Any losses, costs or liabilities directly or indirectly related to cyberattacks or similar incidents may not be covered by, or may exceed the coverage limits of, any or all of our insurance policies.

We collect, process, store and use personal information and other data, and our actual or perceived failure to protect such information and data or comply with data privacy and security laws and regulations could damage our reputation and brand and harm our business and operating results.

We and our vendors are subject to a variety of federal and state data privacy laws, rules, regulations, industry standards and other requirements governing data privacy and the unauthorized disclosure of confidential information, which pose increasingly complex compliance challenges and potentially elevate costs as we collect, process and store personal data related to our past, current and prospective employees, royalty owners and other parties. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. For example, we are subject to various state privacy laws, such as the California Consumer Privacy Act (“CCPA”), which came into effect in January, 2020, and the California Privacy Rights Act (“CPRA”), which expands upon the CCPA and came into effect in January 2023 (with a lookback period until January 2022). The CCPA and the CPRA, among other things, contain new disclosure obligations for businesses that collect personal information about California residents, provide such individuals expanded rights to access, delete, and correct their personal information, and opt-out of certain sales or transfers of personal information, and provide for statutory fines and penalties for certain data security breaches or other CCPA and CPRA violations. The enactment of the CCPA has prompted a wave of similar legislative developments in other states in the United States, which creates the potential for a patchwork of overlapping but different state laws. Any failure or perceived failure by us to comply with data privacy laws, rules, regulations, industry standards and other requirements could result in proceedings or actions against us by individuals, consumer rights groups, government agencies or others. We could incur significant costs in investigating and defending such claims and, if found liable, pay significant damages or fines or be required to make changes to our business. Further, any such proceedings and any subsequent adverse outcomes may subject us to significant negative publicity and an erosion of trust. If any of these events were to occur, our business, financial condition, or results of operations could be materially adversely affected.

Our operations could be disrupted by natural or human causes beyond our control.

Our operations are subject to disruption from natural or human causes beyond our control, including risks from extreme weather events, such as hurricanes, severe storms, floods, droughts, heat waves, winter storms, and ambient temperature, water level, or precipitation changes, as well as wildfires, war, accidents, civil unrest, political events, earthquakes, system failures, cyber threats, terrorist acts and epidemic or pandemic diseases, such as the COVID-19 pandemic, any of which could result in suspension of operations (including those of our customers or suppliers) or harm to people, our assets or the natural environment.

It is difficult to predict with certainty the timing, frequency or severity of such events or how such frequency or severity may change. Any such events could have a material adverse effect on our results of operations or financial condition. Moreover, any changes in ambient temperatures may impact demand for natural gas if it results in lower energy needs for, among other things, temperature control. While concerns over energy security have, in some situations, seen increased demand for natural gas, sustained concerns over energy security may result in an accelerated adoption of renewable energy and other alternative energy generation or storage, or energy efficiency, technologies. Any such accelerated adoption of alternative energy sources or energy efficiency improvements may decrease demand for our products or otherwise adversely impact our business or results of operations.

In addition, our headquarters are located in Oklahoma City, Oklahoma, an area that experiences severe weather events, including tornadoes and earthquakes. Our information systems and administrative and management processes are primarily provided to our various drilling projects and producing wells throughout the United States from this location, which could be disrupted if a catastrophic event, such as a tornado, power outage or act of terror, destroyed or severely damaged our headquarters. Any such catastrophic event could harm our ability to conduct normal operations and could adversely affect our business.

A deterioration in general economic, political, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.

Historically, concerns about global economic growth and international political stability have had a significant impact on global financial markets and commodity prices, including petroleum products. If the economic or political climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and materially adversely impact our results of operations, liquidity and financial condition. The global market is also continuing to experience inflationary pressure, including rising fuel costs, a tightening steel market and labor and supply chain shortages, which could result in increases to our operating and capital costs that are not fixed.

Military and other armed conflicts, including terrorist activities, and related price volatility and geopolitical instability, could materially and adversely affect our business and results of operations.

Military and other armed conflicts, terrorist attacks and the threat of both, whether domestic or foreign, could cause further instability in the global financial and energy markets. Continued instability in Europe and the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices, including petroleum products, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

For example, in late February 2022, Russia launched a military invasion against Ukraine. Sustained conflict and disruption in the region is likely in the near term, and the longer-term duration of the war is uncertain. The Russian invasion has caused, and could intensify, volatility in natural gas, oil and NGL prices, driving a sharp upward spike in the short term, and may have an impact on global growth prospects, which could in turn affect demand for natural gas and oil. In addition, any exacerbation or spillover of the current armed conflict between Israel and Hamas into the broader region could produce similar impacts. Any such volatility, impacts on demand and disruptions may also magnify the impact of other risk factors described in this report.

Financial Risks Related to our Business

We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by industry conditions.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. In the past, low commodity prices have caused and may continue to cause lenders to increase the interest rates under upstream operators' credit facilities, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. Additionally, certain financial institutions have announced their intention to cease investment banking and corporate lending activities in the North American gas and oil sector or have established climate-related funding commitments that could have the effect of limiting their investment in us or our industry. If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. Additionally, challenges in the economy have led and could further lead to reductions in the demand for gas and oil, or further reductions in the prices of gas and oil, or both, which could have a negative impact on our financial position, results of operations and cash flows.

Restrictive covenants in certain of our debt agreements could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our debt agreements impose operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things:

- incur additional indebtedness;
- make investments or loans;
- create liens;
- consummate mergers and similar fundamental changes;
- make restricted payments;
- make investments in unrestricted subsidiaries;
- enter into transactions with affiliates; and
- use the proceeds of asset sales.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under certain of our debt agreements. The restrictions contained in the covenants could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise to restrict our activities or business plan; and
- adversely affect our ability to finance our operations, enter into acquisitions or divestitures to engage in other business activities that would be in our interest.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the Plan and the transactions contemplated thereby.

In connection with the disclosure statement, we filed with the Bankruptcy Court, and the hearing to consider confirmation of the Plan, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks, and the assumptions underlying the projections and/or valuation estimates may prove to be incorrect in material respects. Actual results may vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

Risks Related to the Southwestern Merger

Chesapeake and Southwestern must obtain certain regulatory approvals and clearances to consummate the Southwestern Merger, which, if delayed, not granted or granted with unacceptable conditions, could prevent, substantially delay or impair consummation of the merger, result in additional expenditures of money and resources or reduce the anticipated benefits of the merger.

At any time before or after consummation of the Southwestern Merger, the U.S. Department of Justice or the Federal Trade Commission, or any state attorney general, could take such action under the antitrust laws as it deems necessary or desirable in the public interest, including but not limited to seeking to enjoin the completion of the merger, seeking divestiture of substantial assets of the parties or requiring the parties to license, or hold separate, assets or terminate existing relationships and contractual rights. Private parties may also seek to take legal action under the antitrust laws under certain circumstances. Such conditions or changes and the process of obtaining regulatory approvals could have the effect of delaying or impeding consummation of the Southwestern

Merger or of imposing additional costs or limitations on Chesapeake or Southwestern following completion of the merger, any of which might have an adverse effect on Chesapeake or Southwestern following completion of the merger and may diminish the anticipated benefits of the Southwestern Merger.

The Southwestern Merger is subject to various closing conditions, and any delay in completing the merger may reduce or eliminate the benefits expected.

The Southwestern Merger is subject to the satisfaction of a number of other conditions beyond the parties' control that may prevent, delay or otherwise materially adversely affect the completion of the merger. These conditions include, among other things, Southwestern shareholder approval of the merger agreement, Chesapeake shareholder approval of the issuance of Chesapeake common stock in connection with the merger and the expiration or termination of all applicable waiting periods (and any extensions thereof) under the HSR Act and any commitment to, or agreement (including any timing agreement) with, any governmental entity to delay the consummation of, or not to consummate before a certain date, the Southwestern Merger. Chesapeake cannot predict with certainty whether and when any of these conditions will be satisfied. Any delay in completing the Southwestern Merger could cause the combined company not to realize, or delay the realization of, some or all of the benefits that the companies expect to achieve from the Southwestern Merger.

The merger agreement limits Chesapeake's and Southwestern's respective ability to pursue alternatives to the Southwestern Merger, which may discourage other companies from making a favorable alternative transaction proposal and, in specified circumstances, could require Chesapeake or Southwestern to pay the other party a termination fee.

The merger agreement contains certain provisions that restrict each of Chesapeake's and Southwestern's ability to directly or indirectly solicit competing acquisition proposals or to enter into discussions concerning, or provide confidential information in connection with, any proposal or offer that constitutes, or would reasonably be expected to lead to, a competing acquisition proposal, and Chesapeake and Southwestern have each agreed to certain terms and conditions relating to their ability to engage in, continue or otherwise participate in any discussions with respect to, provide a third party confidential information with respect to or enter into any acquisition agreement with respect to certain unsolicited proposals that constitute or are reasonably likely to lead to a competing proposal. Further, even if the Chesapeake Board of Directors of Directors or the Southwestern Board of Directors of Directors changes, withdraws, modifies, or qualifies its recommendation, unless the merger agreement has been terminated in accordance with its terms, both parties will still be required to submit the proposals regarding the Southwestern Merger to a vote at their respective special meetings. In addition, Chesapeake and Southwestern generally have an opportunity to offer to modify the terms of the merger agreement in response to a competing acquisition proposal or intervening event before the board of directors of the other party may withdraw or qualify their respective recommendations. The merger agreement further provides that, under specified circumstances, including in the event that either Southwestern or Chesapeake terminates the merger agreement in response to an acquisition proposal from a third party that their respective board of directors determines constitutes a superior offer, Southwestern may be required to reimburse Chesapeake's expenses up to approximately $55.6 million or pay Chesapeake a termination fee equal to $260.0 million, less any expenses previously paid, and Chesapeake may be required to reimburse Southwestern's expenses up to approximately $37.3 million or pay Southwestern a termination fee equal to $389.0 million, less any expenses previously paid.

These provisions could discourage a potential third-party acquirer or other strategic transaction partner that might have an interest in Chesapeake or Southwestern from considering or pursuing an alternative transaction with either party or proposing such a transaction. These provisions might also result in a potential third-party acquirer or other strategic transaction partner proposing to pay a lower price than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances.

The market price for Chesapeake common stock following the closing may be affected by factors different from those that historically have affected or currently affect Chesapeake common stock and Southwestern common stock.

Upon completion of the merger, Southwestern shareholders who receive Chesapeake common stock will become shareholders of Chesapeake. Chesapeake's financial position may differ from its financial position before the completion of the merger, and the results of operations of the combined company may be affected by some factors that are different from those currently affecting the results of operations of Chesapeake and those currently affecting the results of operations of Southwestern. Accordingly, the market price and performance of Chesapeake common stock is likely to be different from the performance of Southwestern common stock, or Chesapeake common stock in the absence of the merger. In addition, general fluctuations in stock markets could have a material adverse effect on the market for, or liquidity of, Chesapeake common stock, regardless of Chesapeake's actual operating performance.

Completion of the Southwestern Merger may trigger change in control or other provisions in certain agreements to which Chesapeake, Southwestern or any of their respective subsidiaries or joint ventures is a party.

The completion of the Southwestern Merger may trigger change in control or other provisions in certain agreements to which Chesapeake, Southwestern or any of their respective subsidiaries or joint ventures is a party. If Chesapeake or Southwestern are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under such agreements, potentially terminate such agreements, or seek monetary damages. Even if Chesapeake or Southwestern are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate such agreements on terms less favorable to Chesapeake, Southwestern or the applicable subsidiary or joint venture.

Chesapeake and Southwestern are expected to incur significant transaction costs in connection with the Southwestern Merger, which may be in excess of those anticipated by them.

Chesapeake and Southwestern have incurred and are expected to continue to incur a number of non-recurring costs associated with negotiating and completing the Southwestern Merger, combining the operations of the two companies and achieving desired synergies. These costs have been, and will continue to be, substantial and, in many cases, will be borne by Chesapeake and Southwestern whether or not the Southwestern Merger is completed. A substantial majority of non-recurring expenses will consist of transaction costs, including, among others, fees paid to financial, legal, accounting and other advisors, employee retention, severance and benefit costs, and filing fees. Chesapeake will also incur costs related to formulating and implementing integration plans, including facilities and systems consolidation costs and other employment-related costs. Chesapeake and Southwestern will continue to assess the magnitude of these costs, and additional unanticipated costs may be incurred in connection with the Southwestern Merger and the integration of the two companies' businesses. While Chesapeake and Southwestern have assumed that a certain level of expenses would be incurred, there are many factors beyond their control that could affect the total amount or the timing of the expenses. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not offset integration-related costs and achieve a net benefit in the near term, or at all. The costs described above and any unanticipated costs and expenses, many of which will be borne by Chesapeake or Southwestern even if the Southwestern Merger is not completed, could have an adverse effect on Chesapeake's or Southwestern's financial condition and operating results.

The Merger Agreement subjects Chesapeake and Southwestern to restrictions on their respective business activities prior to the effective time of the Southwestern Merger.

The merger agreement subjects Chesapeake and Southwestern to restrictions on their respective business activities prior to the effective time. The merger agreement obligates each of Chesapeake and Southwestern to generally conduct its businesses in the ordinary course until the effective time and to use its reasonable best efforts to preserve substantially intact its present business organization, goodwill and assets, to keep available the services of its current officers and employees and preserve its existing relationships with governmental entities and its significant customers, suppliers, licensors, licensees, distributors, lessors and others having significant business dealings with it. These restrictions could prevent Chesapeake and Southwestern from pursuing certain business opportunities that arise prior to the effective time and are outside the ordinary course of business.

Uncertainties associated with the Southwestern Merger may cause a loss of management personnel and other key employees of Chesapeake and Southwestern, which could adversely affect the future business and operations of the combined company following the merger.

Chesapeake and Southwestern are dependent on the experience and industry knowledge of their respective officers and other key employees to execute their business plans. The combined company's success after the Southwestern Merger will depend in part upon its ability to retain key management personnel and other key employees of both Chesapeake and Southwestern. Current and prospective employees of Chesapeake and Southwestern may experience uncertainty about their roles within the combined company following the Southwestern Merger or other concerns regarding the timing and completion of the merger or the operations of the combined company following the merger, any of which may have an adverse effect on the ability of Chesapeake and Southwestern to retain or attract key management and other key personnel. If Chesapeake and Southwestern are unable to retain personnel, including key management, who are critical to the future operations of the companies, Chesapeake and Southwestern could face disruptions in their operations, loss of existing customers, loss of key information, expertise or know-how and unanticipated additional recruitment and training costs. In addition, the loss of key personnel could diminish the anticipated benefits of the Southwestern Merger. No assurance can be given that the combined company, following the Southwestern Merger, will be able to retain or attract key management personnel and other key employees to the same extent that Chesapeake and Southwestern have previously been able to retain or attract their own employees.

The Southwestern Merger may not be completed, and the merger agreement may be terminated in accordance with its terms. Failure to complete the Southwestern Merger could negatively impact Chesapeake's stock and have a material adverse effect on our results of operations, cash flows and financial position.

Chesapeake or Southwestern may elect to terminate the merger agreement in accordance with its terms in certain circumstances as further detailed in the merger agreement. If the Southwestern Merger is not completed for any reason, including as a result of failure to obtain all requisite regulatory approvals or if the Chesapeake shareholders or Southwestern shareholders fail to approve the applicable proposals, the ongoing businesses of Chesapeake and Southwestern may be materially adversely affected and, without realizing any of the benefits of having completed the merger, Chesapeake and Southwestern would be subject to a number of risks, including the following:

• Chesapeake may experience negative reactions from the financial markets, including negative impacts on its stock price;

• Chesapeake and its subsidiaries may experience negative reactions from customers, suppliers, vendors, landlords, joint venture partners and other business partners;

• Chesapeake will still be required to pay certain significant costs relating to the Southwestern Merger, such as legal, accounting, financial advisor and printing fees;

• Chesapeake may be required to pay a termination fee as required by the merger agreement;

• the merger agreement places certain restrictions on the conduct of the respective businesses pursuant to the terms of the merger agreement, which may delay or prevent Chesapeake from undertaking business opportunities that, absent the merger agreement, may have been pursued;

• matters relating to the Southwestern Merger (including integration planning) require substantial commitments of time and resources by each company's management, which may have resulted in the distraction of each company's management from ongoing business operations and pursuing other opportunities that could have been beneficial to the companies; and

• litigation related to any failure to complete the Southwestern Merger or related to any enforcement proceeding commenced against Chesapeake to perform its obligations pursuant to the merger agreement.

If the Southwestern Merger is not completed, the risks described above may materialize, which may have a material adverse effect on Chesapeake's results of operations, cash flows, financial position and stock price.

Litigation relating to the Southwestern Merger could result in an injunction preventing completion of the merger, substantial costs to Chesapeake and Southwestern and/or may adversely affect the combined company's business, financial condition or results of operations following the merger.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger or other business combination agreements. Even if such a lawsuit is without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on Chesapeake's and Southwestern's respective liquidity and financial condition.

Lawsuits that may be brought against Chesapeake, Southwestern or their respective directors could also seek, among other things, injunctive relief or other equitable relief, including a request to rescind parts of the merger agreement already implemented and to otherwise enjoin the parties from consummating the Southwestern Merger. One of the conditions to the closing of the Southwestern Merger is that no injunction by any court or other tribunal of competent jurisdiction has been entered and continues to be in effect and no law has been adopted or is effective, in either case that prohibits or makes illegal the closing of the merger. Consequently, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Southwestern Merger, that injunction may delay or prevent the merger from being completed within the expected timeframe or at all, which may adversely affect Chesapeake's and Southwestern's respective business, financial position and results of operation.

There can be no assurance that any of the defendants will be successful in the outcome of any pending or any potential future lawsuits. The defense or settlement of any lawsuit or claim that remains unresolved at the time the Southwestern Merger is completed may adversely affect Chesapeake's and Southwestern's business, financial condition, results of operations and cash flows.

Risks Relating to the Combined Company Following the Merger

The combined company may be unable to integrate the businesses of Chesapeake and Southwestern successfully or realize the anticipated benefits of the Southwestern Merger.

The Southwestern Merger involves the combination of two companies that currently operate as independent public companies. The combination of two independent businesses is complex, costly and time consuming, and each of Chesapeake and Southwestern will be required to devote significant management attention and resources to integrating the business practices and operations of Southwestern into Chesapeake. Potential difficulties that Chesapeake and Southwestern may encounter as part of the integration process include the following:

- the inability to successfully combine the business of Chesapeake and Southwestern in a manner that permits the combined company to achieve, on a timely basis, or at all, the enhanced revenue opportunities and cost savings and other benefits anticipated to result from the Southwestern Merger;

- complexities associated with managing the combined businesses, including difficulty addressing possible differences in operational philosophies and the challenge of integrating complex systems, technology, networks and other assets of each of the companies in a seamless manner that minimizes any adverse impact on customers, suppliers, employees and other constituencies;

- the assumption of contractual obligations with less favorable or more restrictive terms; and

- potential unknown liabilities and unforeseen increased expenses or delays associated with the Southwestern Merger.

In addition, Chesapeake and Southwestern have operated and, until the completion of the Southwestern Merger, will continue to operate, independently. It is possible that the integration process could result in:

- diversion of the attention of each company's management; and

- the disruption of, or the loss of momentum in, each company's ongoing businesses or inconsistencies in standards, controls, procedures and policies.

Any of these issues could adversely affect each company's ability to maintain relationships with customers, suppliers, employees and other constituencies or achieve the anticipated benefits of the Southwestern Merger or could reduce each company's earnings or otherwise adversely affect the business and financial results of the combined company following the merger.

The market price for Chesapeake common stock following the closing may be affected by factors different from those that historically have affected or currently affect Chesapeake common stock.

Upon completion of the Southwestern Merger, Southwestern shareholders who receive Chesapeake common stock will become shareholders of Chesapeake. Chesapeake's financial position may differ from its financial position before the completion of the Southwestern Merger, and the results of operations of the combined company may be affected by some factors that are different from those currently affecting the results of operations of Chesapeake and those currently affecting the results of operations of Southwestern. Accordingly, the market price and performance of Chesapeake common stock is likely to be different from the performance of Chesapeake common stock in the absence of the merger.

The synergies attributable to the Southwestern Merger may vary from expectations.

The combined company may fail to realize the anticipated benefits and synergies expected from the Southwestern Merger, which could adversely affect the combined company's business, financial condition and operating results. The success of the merger will depend, in significant part, on the combined company's ability to successfully integrate the acquired business, grow the revenue of the combined company and realize the anticipated strategic and financial performance benefits and synergies from the combination. However, achieving these benefits requires, among other things, realization of the targeted cost and commercial synergies expected from the merger. This growth and the anticipated benefits of the transaction may not be realized fully or at all or may take longer to realize than expected. Actual operating, technological, strategic and revenue opportunities, if achieved at all, may be less significant than expected or may take longer to achieve than anticipated. If the combined company is not able to achieve these objectives and realize the anticipated benefits and synergies expected from the Southwestern Merger within the anticipated timing or at all, the combined company's business, financial condition and operating results may be adversely affected, the combined company's earnings per share may be diluted, the accretive effect of the merger may decrease or be delayed and the share price of the combined company may be negatively impacted.

The future results of the combined company following the Southwestern Merger will suffer if the combined company does not effectively manage its expanded operations.

Following the Southwestern Merger, the size of the business of the combined company will increase significantly. The combined company's future success will depend, in part, upon its ability to manage this expanded business, which will pose substantial challenges for management, including challenges related to the management and monitoring of new operations and associated increased costs and complexity. The combined company may also face increased scrutiny from governmental authorities as a result of the significant increase in the size of its business. There can be no assurances that the combined company will be successful or that it will realize the expected operating efficiencies, cost savings, revenue enhancements or other benefits currently anticipated from the Southwestern Merger.

The Southwestern Merger may result in a loss of customers, suppliers, vendors, landlords, joint venture partners and other business partners and may result in the termination of existing contracts.

Following the Southwestern Merger, some of the customers, suppliers, vendors, landlords, joint venture partners and other business partners of Chesapeake or Southwestern may terminate or scale back their current or prospective business relationships with the combined company. In addition, Chesapeake and Southwestern have contracts with customers, suppliers, vendors, landlords, joint venture partners and other business partners that may require Chesapeake or Southwestern to obtain consents from these other parties in connection with the Southwestern Merger, which may not be obtained on favorable terms or at all. If relationships with customers, suppliers, vendors, landlords, joint venture partners and other business partners are adversely affected by the Southwestern Merger, or if the combined company, following the merger, loses the benefits of the contracts of Chesapeake or Southwestern, the combined company's business and financial performance could suffer.

The combined company will have a significant amount of indebtedness, which will limit its liquidity and financial flexibility, and any downgrade of its credit rating could adversely impact the combined company. The combined company may also incur additional indebtedness in the future.

As of September 30, 2023, Chesapeake and Southwestern had total long-term indebtedness of approximately $2.0 billion and $4.1 billion, respectively. Accordingly, the combined company will have substantial indebtedness following completion of the Southwestern Merger. In addition, subject to the limits contained in the documents governing such indebtedness, the combined company may be able to incur substantial additional debt from time to time to finance working capital, capital expenditures, investments or acquisitions or for other purposes. The combined company's indebtedness and other financial commitments have important consequences to its business, including, but not limited to:

- making it more difficult for the company to satisfy its obligations with respect to senior notes and other indebtedness due to the increased debt-service obligations, which could, in turn, result in an event of default on such other indebtedness or the senior notes;

- requiring the combined company to dedicate a substantial portion of its cash flows from operations to debt service payments, thereby limiting its ability to fund working capital, capital expenditures, investments or acquisitions and other general corporate purposes;

- increasing the combined company's vulnerability to general adverse economic and industry conditions, including low commodity price environments;

- limiting the combined company's ability to obtain additional financing due to higher costs and more restrictive covenants;

- limiting the combined company's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates; and

- placing the combined company at a competitive disadvantage compared with its competitors that have proportionately less debt and fewer guarantee obligations.

In addition, Chesapeake and Southwestern receive credit ratings from rating agencies in the U.S. with respect to their indebtedness. Any credit downgrades resulting from the Southwestern Merger or otherwise could adversely impact the combined company's ability to access financing and trade credit, require the combined company to provide additional letters of credit or other assurances under contractual arrangements and increase the combined company's interest rate under any credit facility borrowing as well as the cost of any other future debt.

Legal and Regulatory Risks

We are subject to extensive governmental regulation, which can change and could adversely impact our business.

Our operations are subject to extensive federal, state, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of gas, oil and NGL, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes, and tribal laws for a minor portion of our acreage. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. Moreover, the Biden Administration's increased focus on the climate change impacts of federal actions could result in additional restrictions surrounding onshore drilling, onshore federal lease availability, and restrictions on the ability to obtain required permits, which could have a material adverse impact on our operations. For example, in January 2024, the Biden administration announced a temporary pause on the DOE's review of pending applications for authorization to export LNG to non-Free Trade Agreement countries until the DOE updates its underlying analyses for such decisions using more current data to account for considerations like potential energy cost increases for consumers and manufacturers or the latest assessment of the impact of GHG emissions. The temporary pause is not expected to affect LNG exports that have already been authorized. While this pause may not directly impact our exploration, production, and development activities, it may affect the demand for our products, which could have a material adverse effect on our business and financial position and impact our future business strategy. We may be required to make large, sometimes unexpected, expenditures to comply with applicable governmental laws, rules, regulations, permits or orders.

In addition, changes in public policy have affected, and in the future could further affect, our operations. At both the federal and state level, for example, there are an increasing number of legislative initiatives and proposals that may lead to reduced demand for fossil fuels such as oil and gas. These include certain tax advantages and other subsidies to support alternative energy sources or that mandate the use of specific fuels or technologies, in addition to the promotion of research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The IRA, signed by President Biden in August 2022, provides significant funding and incentives for research, development and implementation of low-carbon energy production methods, carbon capture, and other programs directed at addressing climate change. The IRA also includes a methane emissions reduction program that amends the Clean Air Act to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a “waste emissions charge” on certain natural gas and oil sources that are already required to report under EPA’s Greenhouse Gas Reporting Program. The EPA released its proposed rule in January 2024 to implement the methane emissions fee with a proposed effective date in 2025 for reporting year 2024 emissions. Regulatory developments could, among other things, restrict production levels, impose price controls, change environmental protection requirements with respect to the treatment of hazardous waste, air emissions, or water discharges, and increase taxes, royalties and other amounts payable to the government. Our operating and compliance costs could increase further if existing laws and regulations are revised, reinterpreted, or if new laws and regulations become applicable to our operations. We do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity. This is particularly true of changes related to pipeline safety, hydraulic fracturing and climate change, as discussed below.

Pipeline Safety. The pipeline assets in which we own interests are subject to stringent and complex regulations related to pipeline safety and integrity management. The PHMSA has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as for certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect “high consequence areas.” Recent PHMSA rules have also extended certain requirements for integrity assessments and leak detections beyond high consequence areas and impose a number of reporting and inspection requirements on regulated pipelines. In November 2021, the PHMSA issued a final rule that expands certain federal pipeline safety requirements to all onshore gas gathering pipelines, regardless of size or location. The final rule establishes two new types of onshore gas gathering pipelines subject to varying degrees of regulation: all onshore gathering line operators are now subject to PHMSA’s annual reporting and incident reporting requirements, and certain previously unregulated rural gas gathering lines must now comply with PHMSA damage prevention and, depending on the size of the pipeline, construction and operational requirements. The final rule became effective on May 16, 2022. Further, legislation funding the PHMSA through 2023 requires the agency to engage in additional rulemaking to amend the integrity management program, emergency response plan, operation and maintenance manual, and pressure control recordkeeping requirements for gas distribution operators; to create new leak detection and repair program obligations; and to set new minimum federal safety standards for onshore gas gathering lines. In May 2023, the PHMSA issued a proposed rule that would require pipelines, underground natural gas storage facilities, and liquefied natural gas facilities to update leak detection and repair programs to require companies to use commercially available technologies to find and fix methane leaks from pipelines and other facilities. At this time, we cannot predict the cost of these requirements or other potential new or amended regulations, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure and/or well construction requirements on hydraulic fracturing operations. State and federal regulatory agencies have also recently focused on a possible connection between the operation of injection wells used for natural gas and oil waste disposal and seismic activity, which has caused some states, such as New Mexico and Texas, to implement seismicity response programs that allow state regulators to modify, suspend, or terminate injection well permits if the state regulator determines that the injection well is contributing to seismic activity. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and potential bans. Additional regulation could also lead to greater opposition to hydraulic fracturing, including litigation.

Climate Change. Continuing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives to reduce GHG emissions, such as carbon dioxide and methane. Policy makers at both the U.S. federal and state levels have adopted, or are considering adopting, rules designed to quantify and limit the emission of GHGs through inventories, limitations and/or taxes on GHG emissions. The EPA and the BLM have issued regulations for the control of methane emissions, which also include leak detection and repair requirements, for the gas and oil industry and are likely to create additional regulations regarding such matters. For example, in November 2021, the EPA proposed new regulations to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound (VOC) emissions from new and existing operations in the gas and oil sector, including the exploration and production, transmission, processing, and storage segments. The EPA issued a supplemental proposed rule in November 2022 to update, strengthen and expand its November 2021 proposed rule. In December 2023, the EPA issued the final rule, which imposes more stringent requirements on the natural gas and oil industry, including phasing out routine flaring of natural gas from new oil wells, requiring all well sites and compressor stations to be routinely monitored for leaks and eliminating or minimizing emissions from common pieces of equipment used in oil and gas operations, such as process controllers, pumps, and storage tanks. This and other rules may require us to incur additional costs or otherwise impact the economics of certain of our operations. Additionally, in November 2022, the BLM issued a proposed rule to reduce the methane waste from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. Because these regulations, and any other similar proposed regulations, are likely to be subject to legal challenge, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, additional future federal GHG regulations of the gas and oil industry remain a significant possibility. In addition, several states in which we operate have imposed limitations designed to reduce methane emissions from gas and oil exploration and production activities. Legislative and state initiatives to date have generally focused on the development of renewable energy standards and/or cap-and-trade and/or carbon tax programs. Renewable energy standards (also referred to as renewable portfolio standards) require electric utilities to provide a specified minimum percentage of electricity from eligible renewable resources, with potential increases to the required percentage over time. The development of a federal renewable energy standard, or the development of additional or more stringent renewable energy standards at the state level could reduce the demand for gas and oil, thereby adversely impacting our earnings, cash flows and financial position. In addition, federal or state carbon taxes or fees could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, several policymakers and governmental agencies, including the SEC, have issued proposed rules that would mandate extensive disclosure of climate-related risks and other information, including risk management, GHG emissions, financial impacts, and related governance and strategy. In addition to potential costs, these disclosures may be used by some activists for potential litigation or to pressure capital providers to restrict or eliminate investments or other funding. For more information see our risk factor titled *“Negative public perception regarding us or our industry could have an adverse effect on our operations.”*

These various legislative, regulatory and other activities addressing GHG emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations, which could require us to incur costs to reduce emissions of GHGs associated with our operations. Limitations on GHG emissions could also adversely affect demand for gas and oil, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity.

Environmental matters and related costs can be significant.

As an owner, lessee or operator of gas and oil properties, we are subject to various federal, state, tribal and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on us for the cost of remediating pollution that results from our operations. Environmental laws may impose strict, joint and several liability, and failure to comply with environmental laws and regulations can result in the imposition of administrative, civil or criminal fines and penalties, as well as injunctions limiting operations in affected areas. Any future costs associated with these matters are uncertain and will be governed by several factors, including future changes to regulatory requirements. Changes in or additions to public policy regarding the protection of the environment could have a significant impact on our operations and profitability.

Increasing attention to ESG matters and our ability to achieve and maintain ESG certifications, goals and commitments may impact our business, financial results or stock price.

In recent years, increasing attention has been given to corporate activities related to ESG matters in public discourse and the investment community. Expectations regarding voluntary ESG initiatives and disclosures and consumer demand for more sustainable products, including alternative forms of energy, may result in increased costs (including but not limited to increased costs related to compliance, stakeholder engagement, contracting and insurance), changes in demand for certain products, increased availability of (and competition from) alternative energy sources and technologies, increased development of and demand for products that do not use fossil fuels or their derivatives, enhanced compliance or disclosure obligations, or other adverse impacts to our business, financial condition, or results of operations. Additionally, such expectations and related activism may result in demand shifts for natural gas, oil and NGL in addition to potentially impacting our access to, and costs of, capital.

While we may at times engage in voluntary initiatives (such as voluntary disclosures, certifications, or targets, among others) or commitments to improve our ESG profile and/or products or to respond to stakeholder expectations, such initiatives or achievement of such commitments may be costly and may not have the desired effect. For example, while we are exploring initiatives related to various energy-related technologies, such as carbon capture and sequestration, this may require us to incur significant costs, and there is no guarantee that markets will develop, either in the manner we anticipate or at all, for the technologies we invest in. Separately, expectations around management of ESG matters continues to evolve rapidly, in many instances due to factors that are out of our control. In addition, we may commit to certain initiatives or goals, and we may not ultimately be able to achieve such commitments or goals, either on the timeframes or costs initially anticipated or at all, due to factors that are within or outside of our control. Moreover, actions or statements that we may take based on expectations, assumptions, or third-party information that we currently believe to be reasonable may subsequently be determined to be erroneous or be subject to misinterpretation. Even if this is not the case, our current actions may subsequently be determined to be insufficient by various stakeholders, and we may be subject to investor or regulator engagement on our ESG initiatives and disclosures, even if such initiatives are currently voluntary. Any failure to comply with investor, customer or other stakeholder expectations and standards, which are evolving, or if we are perceived to not have responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, could cause reputational harm to our business, increase our risk of litigation, and could have a material adverse effect on our results of operations. For example, plaintiffs have brought litigation against various companies, including those in the fossil fuel sector, alleging that such companies created public nuisances by producing, handling or marketing fuels that contributed to climate change or that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts. While we are not currently parties to any such litigation, the ultimate outcomes of such litigation and its impact to us are uncertain; we could incur substantial legal costs associated with defending against these or similar lawsuits in future.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings systems for evaluating companies on their approach to ESG matters. These ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital. To the extent ESG matters negatively affect our reputation, it may also harm our ability to attract or retain employees or customers. Simultaneously, there are efforts by some stakeholders to reduce companies' efforts on certain ESG-related matters. Both advocates and opponents to certain ESG matters are increasingly resorting to a range of activism forms, including media campaigns and litigation, to advance their perspectives. To the extent we are subject to such activism, it may require us to incur costs or otherwise adversely impact our business.

We expect there will likely be increasing levels of regulation, disclosure-related and otherwise, with respect to ESG matters, which will likely lead to increased compliance costs as well as scrutiny that could heighten all of the risks identified in this risk factor. Such ESG matters may also impact our suppliers or customers, which could augment existing, or cause additional, impacts to our business or operations. To date, we have not incurred material ESG-related costs, but we cannot guarantee that we will not incur such costs in the future.

The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business.

We are subject to taxation by various governmental authorities at the federal, state and local levels in the jurisdictions in which we do business. New legislation could be enacted by any of these governmental authorities making it more costly for us to produce natural gas and oil by increasing our tax burden. The IRA was enacted on August 16, 2022, and includes, among other things, a 15% corporate alternative minimum tax (“CAMT”) on adjusted financial statement income and a 1% excise tax on stock buybacks. Based on our book income in the past three years, we do not believe we are subject to the CAMT in 2023. However, we may become subject to the CAMT in future years. Additionally, the Biden administration has called for changes to fiscal and tax policies, which could lead to comprehensive tax reform. For example, federal legislation has been proposed that, if enacted, would impact federal income tax law applicable to the deduction of intangible drilling and development costs, percentage depletion and, the expensing of geological, geophysical, exploration and development costs. Other proposals changing federal income tax law could include an increase to the corporate tax rate, an increase to the excise tax on stock buybacks and the elimination of certain tax credits. If enacted, certain of these proposals could have a correlative impact on state income taxes. In addition, state and local authorities could enact new legislation that would increase various taxes such as sales, severance and ad valorem taxes as well as accelerate the collection of such taxes.

The completion of the Southwestern Merger is anticipated to trigger an annual limitation on the utilization of our tax attributes, reducing their ability to offset future taxable income, which may result in an increase to income tax liabilities. In addition, trading in our New Common Stock, additional issuance of New Common Stock, and certain other stock transactions could lead to an additional, potentially more restrictive, annual limitation.

Upon emergence from bankruptcy on February 9, 2021, the Company experienced an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended (the “Code” and such change, a “Section 382 Ownership Change”), as all of the common stock and preferred stock of the Predecessor, or the old loss corporation, was canceled and replaced with New Common Stock of the Successor, or the new loss corporation (the “First Ownership Change”). As such, an annual limitation was computed based on the fair market value of the new equity immediately after emergence multiplied by the long-term tax-exempt rate in effect for the month of February 2021. This annual limitation will restrict the future utilization of our net operating loss (NOL) carryforwards, disallowed business interest carryforwards and tax credits that existed at the time of emergence.

We anticipate the completion of the Southwestern Merger will result in a Section 382 Ownership Change for purposes of both Southwestern’s tax attributes as well as for our own. Moreover, trading in our stock, additional issuances, and other stock transactions occurring subsequent to the emergence from Bankruptcy could lead to a further Section 382 Ownership Change. In the event of any additional Section 382 Ownership Change, including as a result of the Southwestern Merger, a new annual limitation would be determined at such time that could be more restrictive than the limitation of the First Ownership Change. Depending on the market conditions and our tax basis, an additional Section 382 Ownership Change may result in a net unrealized built-in loss. The annual limitation in such a case would additionally be applied to certain of our tax items other than just NOL carryforwards, disallowed business interest carryforwards and tax credits. For example, a portion of tax depreciation, depletion and amortization would also be subject to the annual limitation for a five-year period following the Section 382 Ownership Change but only to the extent of the net unrealized built-in loss existing at the time of the additional Section 382 Ownership Change. Whether the new annual limitation would be more restrictive would depend on the value of our stock and the long-term tax-exempt rate in effect at the time of such Section 382 Ownership Change. Assuming that generally higher long-term tax-exempt rates continue to apply as compared to prior years, we believe that the annual limitation on the utilization of our tax attributes expected to result from the Southwestern Merger will be less restrictive than the First Ownership Change. As a result, the new limitation would generally only apply to those tax attributes generated subsequent to the First Ownership Change. However, if the value of our common stock or long-term tax-exempt rates have decreased at the time the additional Section 382 Ownership Change occurs, such ownership change may be more restrictive than the First Ownership Change and would apply to certain of the tax attributes existing at the time of the additional Section 382 Ownership Change, including those remaining from the time of the First Ownership Change.

Some states impose similar limitations on tax attribute utilization upon experiencing an additional Section 382 Ownership Change.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 1C. *Cybersecurity*

Cybersecurity Risk Management and Strategy

We have developed and implemented a cybersecurity risk management program intended to protect the confidentiality, integrity, and availability of our critical systems and information.

We design and assess our cybersecurity risk management program guided by the NIST Cybersecurity Framework. This does not imply that we meet any particular technical standards, specifications, or requirements, only that we use these as a guide to help us identify, assess and manage cybersecurity risks relevant to our business.

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, but is not limited to, the following key elements:

- risk assessments designed to help identify material cybersecurity risks to our critical systems and information;
- a security team principally responsible for managing our cybersecurity risk assessment processes, our security controls, and our response to cybersecurity incidents;
- the use of external service providers, where appropriate, to assess, test or otherwise assist with aspects of our security processes;
- systems for protecting information technology systems and monitoring for suspicious events, such as threat protection, firewall and anti-virus software;
- cybersecurity awareness training of our employees and contractors, including incident response personnel, and senior management;
- a cybersecurity incident response plan that includes procedures for responding to cybersecurity incidents; and
- a third-party risk management process for service providers, suppliers, software, and vendors who access our data and/or systems.

We have not identified risks from known cybersecurity threats, including as a result of any prior cybersecurity incidents, that have materially affected or are reasonably likely to materially affect us, including our operations, business strategy, results of operations, or financial condition. We face certain ongoing risks from cybersecurity threats that, if realized, are reasonably likely to materially affect us, including our operations, business strategy, results of operations, or financial condition. See Item 1A. Risk Factors "*Cyber-attacks targeting systems and infrastructure used by the gas and oil industry and related regulations may adversely impact our operations and, if we or our third-party providers are unable to obtain and maintain adequate protection for our key systems and data, our business may be harmed.*"

Cybersecurity Governance

Our Board of Directors considers cybersecurity risk as a critical part of the enterprise and its risk oversight function and has delegated to its Audit Committee oversight of cybersecurity and other information technology risks. Our Audit Committee oversees management's implementation of our cybersecurity risk management program.

Our Audit Committee receives quarterly updates from management on our cybersecurity risks. In addition, management updates our Audit Committee, as necessary, regarding any material cybersecurity incidents.

Our Audit Committee reports to the full Board of Directors regarding its activities, including those related to cybersecurity. Our Board of Directors also receives briefings from management on our cyber risk management program. Board members receive presentations on cybersecurity topics from information security management, internal security staff, our internal audit group and external experts as part of our Board of Director's continuing education on topics that impact public companies.

Our Cybersecurity Manager is responsible for assessing and managing risks from cybersecurity threats, our overall cybersecurity risk management program and supervises both our internal cybersecurity personnel and our retained external cybersecurity consultants. Our Cybersecurity Manager is responsible for reporting material incidents to our Cybersecurity Committee that includes our Chief Financial Officer, General Counsel and Corporate Secretary, and our Chief Information Officer. Our internal cybersecurity team has over 50 years of combined experience in information security and maintains several cybersecurity certificates including but not limited to CISSP, CISM, SRISC, GSEC, and GCFE. Our Cybersecurity team regularly participates with private energy industry and federal security working groups and organizations.

Our management team stays informed about and monitors efforts to prevent, detect, mitigate, and remediate cybersecurity risks and incidents through various means, including, as appropriate, briefings from internal security personnel, threat intelligence and other information obtained from governmental, public or private sources, such as external consultants engaged by us, and alerts and reports produced by security tools deployed in the IT environment.

Item 2. *Properties*

Information regarding our properties is included in Item 1. Business and in the Supplementary Information included in Item 8 of Part II of this report.

Item 3. ***Legal Proceedings***

Litigation and Regulatory Proceedings

We are involved in various regulatory proceedings, lawsuits and disputes arising in the ordinary course of our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. The majority of the legal proceedings that were in existence prior to the Petition Date were settled during the Chapter 11 Cases or will be resolved in connection with the claims reconciliation process before the Bankruptcy Court. Any allowed claim related to such prepetition litigation will be treated in accordance with the Plan.

See Note 7 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings. Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Environmental Contingencies

The nature of the natural gas and oil business carries with it certain environmental risks for us and our subsidiaries. We have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. We conduct periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, we may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

Item 4. ***Mine Safety Disclosures***

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17CFR 229.104) is included in Exhibit 95.1 to this Form 10-K. On March 20, 2023, we divested our mining assets to WildFire Energy I LLC.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Common Stock

Upon our emergence from Chapter 11 bankruptcy on February 9, 2021, our then-authorized common stock and preferred stock were canceled and released under the Plan without receiving any recovery on account thereof. In accordance with the Plan confirmed by the Bankruptcy Court on February 9, 2021, we issued 97,097,081 shares of New Common Stock of the Successor, which are listed on the Nasdaq Stock Market LLC under the symbol CHK. In addition, on February 9, 2021, we issued 11,111,111 Class A Warrants, 12,345,679 Class B Warrants and 9,768,527 Class C Warrants, each of which were exercisable for one share of common stock per warrant at the initial exercise prices of $27.63, $32.13 and $36.18 per share, respectively. The warrants are immediately exercisable and will expire on February 9, 2026. For more information regarding our emergence from Chapter 11 bankruptcy and our Plan of Reorganization, see Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report. Additionally, more information on our New Common Stock and Warrants can be found in Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

Dividends

We declared the first quarterly dividend on our New Common Stock in the second quarter of 2021, which consisted of a base dividend per share. In March 2022, we adopted a variable return program that resulted in the payment of an additional variable dividend equal to the sum of Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. The declaration and payment of any future dividend is subject to the approval of our Board of Directors in its discretion. Since the initial base dividend declared during the second quarter of 2021, we have incrementally increased the base dividend per share. For additional information on our dividends, see Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

Repurchases of Equity Securities; Unregistered Sales of Equity Securities and Use of Proceeds

On December 2, 2021, we announced that our Board of Directors authorized the repurchase of up to $1.0 billion in aggregate value of our common stock and/or warrants from time to time. In June 2022, our Board of Directors authorized an increase in the size of the share repurchase program from $1.0 billion to $2.0 billion in aggregate value of our common stock and/or warrants. The repurchase authorization permits repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, compliance with the Company's debt agreements and other appropriate factors. The share repurchase program expired on December 31, 2023. The following table provides information regarding purchases of our common stock made by us during the quarter ended December 31, 2023.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions)
October 1 - October 31	149,050	$ 85.95	149,050	$ 610
November 1 - November 30	348,600	$ 82.54	348,600	$ 581
December 1 - December 31	129,797	$ 76.13	129,797	$ —
Total	627,447	$ 82.03	627,447	

Stockholders

As of February 15, 2024, there were approximately 141 holders of record of our common stock.

Item 6. ***Reserved***

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

This Management's Discussion and Analysis of Financial Condition and Results of Operations is intended to provide a reader of our financial statements with management's perspective on our financial condition, liquidity, results of operations and certain other factors that may affect our future results. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with Item 8 of Part II of this report.

Introduction

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties to produce natural gas, oil and NGL from underground reservoirs. We own a large portfolio of onshore U.S. unconventional natural gas assets, including interests in approximately 5,000 natural gas wells as of December 31, 2023. Our natural gas resource plays are the Marcellus Shale in the northern Appalachian Basin in Pennsylvania ("Marcellus") and the Haynesville/Bossier Shales in northwestern Louisiana ("Haynesville"). Our liquids-rich resource play was in the Eagle Ford Shale in South Texas ("Eagle Ford"). During 2023, we completed our exit from Eagle Ford through three separate divestiture transactions, with aggregate proceeds from these three transactions exceeding $3.5 billion, subject to customary post-closing adjustments.

Our strategy is to create shareholder value through the responsible development of our significant resource plays while continuing to be a leading provider of affordable, reliable, lower carbon energy to markets in need. We continue to focus on improving margins through operating efficiencies and financial discipline and improving our ESG performance. To accomplish these goals, we intend to allocate our human resources and capital expenditures to projects we believe offer the highest cash return on capital invested, to deploy leading drilling and completion technology throughout our portfolio, and to take advantage of acquisition and divestiture opportunities to strengthen our portfolio. We also intend to continue to dedicate capital to projects that reduce the environmental impact of our natural gas and oil producing activities. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation and general and administrative), through operational efficiencies and improving our production volumes from existing wells.

Leading a responsible energy future is foundational to Chesapeake's success. Our core values and culture demand we continuously evaluate the environmental impact of our operations and work diligently to improve our ESG performance across all facets of our Company. Our path to answering the call for affordable, reliable, lower carbon energy begins with our goal to achieve net zero GHG emissions (Scope 1 and 2) by 2035. To meet this challenge, we have set meaningful goals including:

- Eliminate routine flaring from all new wells completed from 2021 forward, and enterprise-wide by 2025;
- Reduce our methane intensity to 0.02% by 2025 (achieved approximately 0.02% in 2023 for our natural gas assets); and
- Reduce our GHG intensity to 3.0 metric tons CO_2 equivalent per thousand barrel of oil equivalent by 2025 (achieved approximately 2.1 in 2023 for our natural gas assets).

In July 2021, we announced our plan to receive independent certification of our natural gas production under the MiQ methane standard and EO100™ Standard for Responsible Energy Development. By the end of 2022, we had received certifications for all our operated gas assets in Haynesville and Marcellus as responsibly sourced gas. In 2023, we continued to maintain these independent certifications. The independent certification of our production as responsibly sourced provides a verified approach to tracking our progress towards our commitment to reduce our methane intensity, as well as supporting our overall objective of achieving net-zero Scope 1 and 2 GHG emissions by 2035.

Recent Developments

Merger Agreement

On January 10, 2024, Chesapeake and Southwestern entered into an all-stock merger agreement. Southwestern is an independent energy company engaged in development, exploration and production activities, including related marketing activities, within its operating areas in the Marcellus and Haynesville shale plays. Pursuant to the terms of the merger agreement, at the effective time of the Southwestern Merger, each eligible share of Southwestern common stock issued and outstanding immediately prior to the effective time will be automatically converted into the right to receive 0.0867 of a share of Chesapeake's common stock. Our Board of Directors and the Board of Directors of Southwestern both approved the merger agreement. Subject to the approval of our shareholders and Southwestern shareholders, regulatory approvals and the satisfaction or waiver of other customary closing conditions, the Southwestern Merger is targeted to close in the second quarter of 2024.

Acquisitions

On March 9, 2022, we completed our Marcellus Acquisition pursuant to definitive agreements with Chief, Radler and Tug Hill, dated January 24, 2022. On November 1, 2021, we completed our Vine Acquisition pursuant to a definitive agreement with Vine dated August 10, 2021. These transactions strengthen Chesapeake's competitive position, meaningfully increasing our operating cash flows and adding high quality producing assets and a deep inventory of premium drilling locations, while preserving the strength of our balance sheet.

Divestitures

On March 25, 2022, we closed the sale of our Powder River Basin assets in Wyoming to Continental Resources, Inc. for $450 million in cash, subject to post-closing adjustments, which resulted in the recognition of a gain of approximately $293 million.

On January 17, 2023, we entered into an agreement to sell a portion of our Eagle Ford assets to WildFire Energy I LLC for approximately $1.425 billion, subject to post-closing adjustments. This transaction closed on March 20, 2023 (with an effective date of October 1, 2022) and resulted in the recognition of a gain of approximately $337 million.

On February 17, 2023, we entered into an agreement to sell a portion of our remaining Eagle Ford assets to INEOS Energy for approximately $1.4 billion, subject to post-closing adjustments. This transaction closed on April 28, 2023 (with an effective date of October 1, 2022) and resulted in the recognition of a gain of approximately $470 million.

On August 11, 2023, we entered into an agreement to sell the final portion of our remaining Eagle Ford assets to SilverBow Resources, Inc. ("SilverBow") for approximately $700 million, subject to post-closing adjustments. Subject to the satisfaction of certain commodity price triggers, we may receive up to an additional $50 million cash consideration shortly following the first anniversary of the transaction close date. This transaction closed on November 30, 2023 (with an effective date of February 1, 2023) and resulted in the recognition of a gain of approximately $140 million.

LNG Agreement

On February 13, 2024, we announced our entrance into an LNG export deal that includes executed Sales and Purchase Agreements ("SPA") for long-term liquefaction offtake. Under the SPAs, we will purchase approximately 0.5 million tonnes of LNG per annum from Delfin LNG LLC at a Henry Hub price with a contract targeted start date in 2028, then deliver to Gunvor Group Ltd on a free on board basis with the sales price linked to the Japan Korea Market for a period of 20 years.

Investments - Momentum Sustainable Ventures LLC

During the fourth quarter of 2022, we entered into an agreement with Momentum Sustainable Ventures LLC to build a new natural gas gathering pipeline and carbon capture and sequestration project, which will gather natural gas produced in the Haynesville Shale for re-delivery to Gulf Coast markets, including LNG export. The pipeline is expected to have an initial capacity of 1.7 Bcf/d expandable to 2.2 Bcf/d. The carbon capture portion of the project anticipates capturing and permanently sequestering up to 2.0 million tons per annum of CO2. The natural gas gathering pipeline is projected for a potential in-service date in 2025, and the carbon sequestration portion of the project is subject to regulatory approvals. Through the end of the 2023 Successor Period, we have made total capital contributions of $238 million to the project.

New Credit Facility

On December 9, 2022, we entered into a new senior secured reserve-based revolving credit agreement providing for the New Credit Facility, which features an initial borrowing base of $3.5 billion and aggregate commitments of $2.0 billion. The New Credit Facility includes terms that change favorably upon us receiving and maintaining investment grade ratings by S&P, Moody's and/or Fitch and the satisfaction of certain other conditions. The New Credit Facility matures in December 2027.

Repurchases of Equity Securities and Dividends

In June 2022, our Board of Directors authorized an increase in the size of our share repurchase program from $1.0 billion to up to $2.0 billion in aggregate value of our common stock and/or warrants. From March 2022 through the 2023 Successor Period, we repurchased approximately 16.0 million shares of our common stock pursuant to the share repurchase program. The share repurchase program expired on December 31, 2023. In addition, we have paid dividends of approximately $487 million, in aggregate, on our common stock during the 2023 Successor Period. In August 2023, we increased our quarterly base dividend rate by 4.5% to $0.575 per share beginning with the dividend that was paid on September 6, 2023.

Warrant Exchange Offer

In August 2022, we announced exchange offers relating to our outstanding Class A Warrants, Class B Warrants, and Class C Warrants. The exchange offers expired in October 2022 and resulted in the issuance of 16,305,984 shares of our common stock in exchange for the cancellation of (i) 4,752,207 Class A Warrants, or approximately 51.4% of the outstanding Class A Warrants, at the time of exchange, (ii) 7,879,030 Class B Warrants, or approximately 64.1% of the outstanding Class B Warrants, at the time of exchange, and (iii) 7,252,004 Class C Warrants, or approximately 64.8% of the outstanding Class C Warrants, at the time of exchange.

Economic and Market Conditions

Instability and conflict in Europe and the Middle East has caused, and could intensify, volatility in natural gas, oil and NGL prices, and may further impact on global growth prospects, which could in turn affect supply and demand for natural gas and oil. In addition, a mild winter in 2023 and historically higher inventory levels have resulted in an observed decline in natural gas pricing in 2023 and at the beginning of 2024. Our 2024 estimated cash flow is partially protected from commodity price volatility due to our current hedge positions that cover approximately 60% of our projected natural gas volumes for 2024. We believe our cost structure and liquidity position will enable us to successfully navigate continued price volatility.

During 2023, our industry continued to experience inflationary pressures, including increased demand for oilfield service equipment, rising fuel costs, and labor shortages, which resulted in observed increases to our operating and capital costs that were not fixed. Uncertainty regarding a potential economic downturn or recession in certain regions, or globally, may introduce new pressures or accelerate or intensify the pressures currently facing the industry. Recent reductions in rig activity in the lower 48 states of the United States allowed service costs to stabilize in the second half of 2023. We continue to monitor these situations and assess their impact on our business, including business partners and customers. For additional discussion regarding risks associated with price volatility and economic deterioration, see Item 1A Risk Factors in this report.

Liquidity and Capital Resources

Liquidity Overview

For the 2023 Successor Period, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations, proceeds from the divestitures of our Eagle Ford assets and borrowings under our New Credit Facility, and our primary uses of cash have been for the development of our natural gas and oil properties, and return of value to stockholders through dividends and equity repurchases. Historically, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations, borrowings under certain credit agreements and dispositions of non-core assets. Our ability to issue additional indebtedness, dispose of assets or access the capital markets was substantially limited during the Chapter 11 Cases and required court approval in most instances. Accordingly, our liquidity in the 2021 Predecessor Period depended mainly on cash generated from operations and available funds under certain credit agreements including the DIP Facility.

We believe we have emerged from the Chapter 11 Cases as a fundamentally stronger company, built to generate sustainable Free Cash Flow with a strengthened balance sheet, large portfolio of onshore U.S. unconventional natural gas assets and improving ESG performance. As a result of the Chapter 11 Cases, we reduced our total indebtedness by $9.4 billion by issuing equity in a reorganized entity to the holders of our FLLO Term Loan, Second Lien Notes, unsecured notes and allowed general unsecured claimants.

In December 2022, we entered into a New Credit Facility and terminated the Exit Credit Facility, repaying all amounts outstanding and extinguishing all commitments thereunder. We believe our cash flow from operations, cash on hand and borrowing capacity under the New Credit Facility, as discussed below, will provide sufficient liquidity during the next 12 months and the foreseeable future. As of December 31, 2023, we had $3.1 billion of liquidity available, including $1.1 billion of cash on hand and $2.0 billion of aggregate unused borrowing capacity available under the New Credit Facility. As of December 31, 2023, we had no outstanding borrowings under our New Credit Facility and $7 million utilized for various letters of credit. See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of our debt obligations, including principal and carrying amounts of our senior notes.

Dividends

We declared the first quarterly dividend on our New Common Stock in the second quarter of 2021, which consisted of a base dividend per share. In March 2022, we adopted a variable return program that resulted in the payment of an additional variable dividend per share equal to the sum of the Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. Under this base and variable dividend approach, we paid dividends of $487 million, in aggregate, on our common stock in the 2023 Successor Period. See Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

The declaration and payment of any future dividend, whether fixed or variable, will remain at the full discretion of the Board and will depend on the Company's financial results, cash requirements, future prospects and other relevant factors. The Company's ability to pay dividends to its stockholders is restricted by (i) Oklahoma corporate law, (ii) its Certificate of Incorporation, (iii) the terms and provisions of the credit agreement governing its New Credit Facility and (iv) the terms and provisions of the indentures governing its 5.50% Senior Notes due 2026, 5.875% Senior Notes due 2029 and 6.75% Senior Notes due 2029.

Derivative and Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. We enter into various derivative instruments to mitigate a portion of our exposure to commodity price declines, but these transactions may also limit our cash flows in periods of rising commodity prices. Our natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil and NGL, allow us to better predict the total revenue we expect to receive. See Item 7A Quantitative and Qualitative Disclosures About Market Risk included in Part II of this report for further discussion on the impact of commodity price risk on our financial position.

Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2023, our material contractual obligations include repayment of senior notes, derivative obligations, asset retirement obligations, lease obligations, capital commitments relating to our investments, undrawn letters of credit and various other commitments we enter into in the ordinary course of business that could result in future cash obligations. In addition, we have contractual commitments with midstream companies and pipeline carriers for future gathering, processing and transportation of natural gas to move certain of our production to market. The estimated gross undiscounted future commitments under these agreements were approximately $2.1 billion as of December 31, 2023. As discussed above, we believe our existing sources of liquidity will be sufficient to fund our near and long-term contractual obligations. See Notes 6, 7, 9, 15, 18 and 20 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

New Credit Facility

On December 9, 2022, the Company, as borrower, entered into a senior secured reserve-based credit agreement providing for the New Credit Facility which features an initial borrowing base of $3.5 billion and aggregate commitments of $2.0 billion. Subject to certain exceptions, the borrowing base will be redetermined semi-annually in or around April and October of each year. The New Credit Facility provides for a $200 million sublimit available for the issuance of letters of credit and a $50 million sublimit available for swingline loans. Borrowings under the credit agreement may be alternate base rate loans or term SOFR loans, at the Company's election. The New Credit Facility contains certain features that, upon receipt and maintenance of investment grade ratings from S&P, Moody's and/or Fitch and the satisfaction of certain other conditions, result in the removal or relaxation of specified negative and financial covenants, among other favorable adjustments. See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Post-Emergence Debt

On the Effective Date, pursuant to the terms of the Plan, the Company, as borrower, entered into a reserve-based credit agreement providing for the Exit Credit Facility which featured an initial borrowing base of $2.5 billion. The aggregate initial elected commitments of the lenders under the Exit Credit Facility were $1.75 billion of revolving Tranche A Loans and $221 million of fully funded Tranche B Loans.

The Exit Credit Facility provided for a $200 million sublimit of the aggregate commitments that were available for the issuance of letters of credit. The Exit Credit Facility bore interest at the ABR (alternate base rate) or LIBOR, at our election, plus an applicable margin (ranging from 2.25–3.25% per annum for ABR loans and 3.25–4.25% per annum for LIBOR loans, subject to a 1.00% LIBOR floor), depending on the percentage of the borrowing base then being utilized. The Tranche A Loans were due to mature 3 years after the Effective Date and the Tranche B Loans were due to mature 4 years after the Effective Date. In December 2022, in conjunction with our entry into the New Credit Facility, the Exit Credit Facility was terminated, repaying all amounts outstanding and extinguishing all commitments thereunder.

On February 2, 2021, the Company issued $500 million aggregate principal amount of its 5.50% Senior Notes due 2026 (the "2026 Notes") and $500 million aggregate principal amount of its 5.875% Senior Notes due 2029 (the "2029 Notes" and, together with the 2026 Notes, the "Notes"). The offering of the Notes was part of a series of exit financing transactions undertaken in connection with the Debtors' Chapter 11 Cases and meant to provide the exit financing originally intended to be provided by the Exit Term Loan Facility pursuant to the Commitment Letter.

Assumption and Repayment of Vine Debt

In conjunction with the Vine Acquisition, Vine's Second Lien Term Loan was repaid and terminated for $163 million inclusive of a $13 million make whole premium with cash on hand, due to the agreement containing a change in control provision making the term loan callable upon closing. Vine's reserve-based loan facility, which had no borrowings as of November 1, 2021, was terminated at the time of the completion of the Vine Acquisition. Additionally, Vine's 6.75% Senior Notes with a principal amount of $950 million, were assumed by the Company at the time of the completion of the Vine Acquisition.

Capital Expenditures

For the year ending December 31, 2024, we currently expect to drill approximately 95 to 115 gross wells across 7 to 9 rigs and plan to invest between approximately $1.25 – $1.35 billion in capital expenditures. We currently plan to fund our 2024 capital program through cash on hand, expected cash flow from our operations and borrowings under our New Credit Facility. We may alter or change our plans with respect to our capital program and expected capital expenditures based on developments in our business, our financial position, our industry or any of the markets in which we operate.

Sources and (Uses) of Cash and Cash Equivalents

The following table presents the sources and uses of our cash and cash equivalents for the periods presented:

	Successor			Predecessor
	Year Ended December 31, 2023	**Year Ended December 31, 2022**	**Period from February 10, 2021 through December 31, 2021**	**Period from January 1, 2021 through February 9, 2021**
Cash provided by (used in) operating activities	$ 2,380	$ 4,125	$ 1,809	$ (21)
Proceeds from divestitures of property and equipment	2,533	407	13	—
Proceeds from New Credit Facility, net	—	1,050	—	—
Proceeds from issuance of senior notes, net	—	—	—	1,000
Proceeds from issuance of common stock	—	—	—	600
Proceeds from warrant exercise	—	27	2	—
Capital expenditures	(1,829)	(1,823)	(669)	(66)
Business combination, net	—	(1,967)	(194)	—
Contributions to investments	(231)	(18)	—	—
Payments on New Credit Facility, net	(1,050)	—	—	—
Payments on Exit Credit Facility, net	—	(221)	(50)	(479)
Payments on DIP Facility borrowings	—	—	—	(1,179)
Debt issuance and other financing costs	—	(17)	(3)	(8)
Cash paid to repurchase and retire common stock	(355)	(1,073)	—	—
Cash paid for common stock dividends	(487)	(1,212)	(119)	—
Other	—	—	(1)	—
Net increase (decrease) in cash, cash equivalents and restricted cash	$ 961	$ (722)	$ 788	$ (153)

Cash Flow from Operating Activities

Cash provided by operating activities was $2.38 billion, $4.12 billion and $1.81 billion in the 2023 Successor Period, 2022 Successor Period and 2021 Successor Period, respectively. Cash used in operating activities was $21 million for the 2021 Predecessor Period. The decrease in the 2023 Successor Period is primarily due to lower prices for the natural gas, oil and NGL we sold as well as decreased sales volumes related to our Eagle Ford divestitures. The increase in the 2022 Successor Period is primarily due to higher prices for the natural gas, oil and NGL we sold and increased volumes sold due to the Vine Acquisition and Marcellus Acquisition. The cash used in the 2021 Predecessor Period was primarily in connection with the payment of professional fees related to the Chapter 11 Cases. Cash flows from operations are largely affected by the same factors that affect our net income, excluding various non-cash items, such as depreciation, depletion and amortization, certain impairments, gains or losses on sales of assets, deferred income taxes and mark-to-market changes in our open derivative instruments. See further discussion below under *Results of Operations*.

Proceeds from Divestitures of Property and Equipment

In the 2023 Successor Period, we sold our Eagle Ford assets through three separate transactions resulting in total cash proceeds of $2.5 billion after customary post-closing adjustments. In the 2022 Successor Period, we sold our Powder River Basin assets to Continental Resources, Inc. for approximately $400 million after customary closing adjustments. In the 2021 Successor Period, we divested certain non-core assets for approximately $13 million. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Proceeds from New Credit Facility, net

In the 2022 Successor Period, we borrowed a net $1.05 billion under the New Credit Facility. We utilized these borrowings to terminate the Exit Credit Facility, including the repayment of outstanding Tranche A Loans and Tranche B Loans thereunder, backstopping certain letters of credit, and the payment of fees and expenses in connection with the termination of the Exit Credit Facility and entry into the New Credit Facility. A portion of the borrowings under the New Credit Facility were repaid with internally generated cash provided by operating activities.

Proceeds from Issuance of Common Stock and Senior Notes

In the 2021 Predecessor Period, we issued $500 million aggregate principal amount of 5.50% 2026 Notes and $500 million aggregate principal amount of 5.875% 2029 Notes for total proceeds of $1.0 billion. Additionally, upon emergence from Chapter 11, we issued 62,927,320 shares of New Common Stock in exchange for $600 million of cash, as agreed upon in the Plan. See Note 6 and Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Capital Expenditures

Our capital expenditures during the 2023 Successor Period were in line with the 2022 Successor Period, primarily as a result of increased drilling and completion activity within our Haynesville operating area, partially offset by reduced activity due to our Eagle Ford divestitures. Our capital expenditures significantly increased in the 2022 Successor Period compared to the 2021 Successor Period, primarily as a result of increased drilling and completion activity in Haynesville and Marcellus, following the Vine Acquisition and Marcellus Acquisition, respectively. In the 2023 Successor Period, our average operated rig count was 11 rigs and 193 spud wells, compared to an average operated rig count of 14 rigs and 217 spud wells in the 2022 Successor Period and 7 rigs and 110 spud wells in the 2021 Successor Period. We completed 166 operated wells in the 2023 Successor Period compared to 216 in the 2022 Successor Period and 112 in the 2021 Successor Period.

Business Combination, net

In the 2022 Successor Period, we completed the Marcellus Acquisition for approximately $2 billion and 9.4 million shares of our common stock. In the 2021 Successor Period, we acquired Vine for approximately 18.7 million shares of our New Common Stock and $253 million cash, less $59 million of cash held by Vine as of the acquisition date. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of these acquisitions.

Contributions to Investments

During the 2023 Successor Period and 2022 Successor Period, contributions to investments were $231 million and $18 million, respectively, which primarily consisted of contributions to our investment with Momentum Sustainable Ventures LLC to build a new natural gas gathering pipeline and carbon capture project. See Note 18 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information.

Payments on New Credit Facility, net

During the 2023 Successor Period, we made net repayments of $1.05 billion on the New Credit Facility, utilizing a portion of the proceeds from the Eagle Ford divestitures and also internally generated cash provided by operating activities.

Payments on Exit Credit Facility, net

In December 2022, we entered into the New Credit Facility and terminated the Exit Credit Facility, repaying all amounts outstanding and extinguishing all commitments thereunder.

Payments on DIP Facility Borrowings

On the Effective Date, the DIP Facility was terminated, and the holders of obligations under the DIP Facility received payment in full in cash; provided that to the extent such lender under the DIP Facility was also a lender under the Exit Credit Facility, such lender's allowed DIP claims were first reduced dollar-for-dollar and satisfied by the amount of its Exit RBL Loans provided as of the Effective Date.

Debt Issuance and Other Financing Costs

During the 2022 Successor Period, we paid $17 million of one-time fees to lenders to establish the New Credit Facility.

Cash Paid to Repurchase and Retire Common Stock

In March 2022, we commenced our share repurchase program. During the 2023 Successor Period, we repurchased 4.4 million shares of our common stock for an aggregate cost of approximately $355 million. During the 2022 Successor Period, we repurchased 11.7 million shares of our common stock for an aggregate cost of $1.1 billion. The repurchased shares of common stock were retired and recorded as a reduction to common stock and retained earnings. See Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Cash Paid for Common Stock Dividends

As part of our dividend program, we paid common stock dividends of $487 million, $1.2 billion and $119 million during the 2023, 2022 and 2021 Successor Periods, respectively. See Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion.

Results of Operations

Year ended December 31, 2023 compared to the year ended December 31, 2022

Below is a discussion of changes in our results of operations for the 2023 Successor Period compared to the 2022 Successor Period.

Natural Gas, Oil and NGL Production and Average Sales Prices

	Successor							
	Year Ended December 31, 2023							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,834	2.22	—	—	—	—	1,834	2.22
Haynesville	1,551	2.30	—	—	—	—	1,551	2.30
Eagle Ford	85	2.25	21	77.80	10	25.62	274	7.64
Total	3,470	2.25	21	77.80	10	25.62	3,659	2.66
Average NYMEX Price		2.74		77.63				
Average Realized Price (including realized derivatives)		2.64		72.89		25.62		2.99

	Successor							
	Year Ended December 31, 2022							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,836	6.03	—	—	—	—	1,836	6.03
Haynesville	1,611	5.92	—	—	—	—	1,611	5.92
Eagle Ford	127	5.64	51	96.10	16	36.76	529	11.76
Powder River Basin	10	5.45	2	95.18	1	53.96	26	10.66
Total	3,584	5.96	53	96.07	17	37.48	4,002	6.77
Average NYMEX Price		6.64		94.23				
Average Realized Price (including realized derivatives)		3.67		66.36		37.48		4.32

Natural Gas, Oil and NGL Sales

	Successor			
	Year Ended December 31, 2023			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 1,483	$ —	$ —	$ 1,483
Haynesville	1,300	—	—	1,300
Eagle Ford	70	596	98	764
Total natural gas, oil and NGL sales	$ 2,853	$ 596	$ 98	$ 3,547

	Successor			
	Year Ended December 31, 2022			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 4,041	$ —	$ —	$ 4,041
Haynesville	3,481	—	—	3,481
Eagle Ford	261	1,798	212	2,271
Powder River Basin	20	66	13	99
Total natural gas, oil and NGL sales	$ 7,803	$ 1,864	$ 225	$ 9,892

Natural gas, oil and NGL sales in the 2023 Successor Period decreased $6.345 billion compared to the 2022 Successor Period. The decrease in Marcellus and Haynesville of $4.739 billion was primarily due to a decrease in revenues from lower average prices received. Additionally, divestitures in Eagle Ford and Powder River Basin resulted in a decrease of $1.606 billion.

Production Expenses

	Successor			
	Year Ended December 31,			
	2023		2022	
		$/Mcfe		$/Mcfe
Marcellus	$ 81	0.12	$ 76	0.11
Haynesville	185	0.33	155	0.26
Eagle Ford	90	0.91	234	1.22
Powder River Basin	—	—	10	0.94
Total production expenses	$ 356	0.27	$ 475	0.33

Production expenses in the 2023 Successor Period decreased $119 million compared to the 2022 Successor Period. The decrease was primarily due to the Eagle Ford and Powder River Basin divestitures, partially offset by an increase of $30 million in Haynesville, primarily due to an increase in saltwater disposal expenses.

Gathering, Processing and Transportation Expenses (“GP&T”)

	Successor			
	Year Ended December 31,			
	2023		2022	
		$/Mcfe		$/Mcfe
Marcellus	$ 433	0.65	$ 381	0.57
Haynesville	263	0.46	313	0.53
Eagle Ford	157	1.57	343	1.78
Powder River Basin	—	—	22	2.32
Total GP&T	$ 853	0.64	$ 1,059	0.73

Gathering, processing and transportation expenses in the 2023 Successor Period decreased $206 million compared to the 2022 Successor Period. The decrease was primarily due to a $208 million decrease due to divestitures in Eagle Ford and Powder River Basin. Additionally, Haynesville decreased $50 million, primarily due to lower rates driven by decreased prices. These decreases were partially offset by a $52 million increase in Marcellus, primarily due to the Marcellus Acquisition in March 2022.

Severance and Ad Valorem Taxes

	Successor			
	Year Ended December 31,			
	2023		2022	
		$/Mcfe		$/Mcfe
Marcellus	$ 14	0.02	$ 17	0.03
Haynesville	105	0.19	75	0.13
Eagle Ford	48	0.48	139	0.71
Powder River Basin	—	—	11	1.09
Total severance and ad valorem taxes	$ 167	0.13	$ 242	0.17

Severance and ad valorem taxes in the 2023 Successor Period decreased $75 million compared to the 2022 Successor Period. The decrease was primarily due to a $102 million decrease due to the Eagle Ford and Powder River Basin divestitures, partially offset by an increase of $30 million in Haynesville due to legislative action that led to changes in the Haynesville severance and ad valorem tax rates.

Natural Gas and Oil Derivatives

	Successor	
	Year Ended December 31,	
	2023	2022
Natural gas derivatives - realized gains (losses)	$ 488	$ (2,998)
Natural gas derivatives - unrealized gains	1,199	611
Total gains (losses) on natural gas derivatives	$ 1,687	$ (2,387)
Oil derivatives - realized losses	$ (38)	$ (576)
Oil derivatives - unrealized gains	88	283
Total gains (losses) on oil derivatives	$ 50	$ (293)
Contingent consideration unrealized losses	$ (9)	$ —
Total gains (losses) on natural gas and oil derivatives	$ 1,728	$ (2,680)

See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a complete discussion of our derivative activity.

Marketing Revenues and Expenses

	Successor	
	Year Ended December 31,	
	2023	2022
Marketing revenues	$ 2,500	$ 4,231
Marketing expenses	2,499	4,215
Marketing margin	$ 1	$ 16

Marketing revenues and expenses decreased in the 2023 Successor Period as a result of decreased natural gas, oil and NGL prices received in our marketing operations. During the 2023 Successor Period, we continued to market production for a portion of the divested Eagle Ford assets pursuant to the transition services agreements.

Exploration Expenses

During the 2023 Successor Period, exploration expense charges of $27 million were primarily the result of $12 million of non-cash impairment charges in unproved properties and $11 million of geological and geophysical expense. During the 2022 Successor Period, exploration expense charges of $23 million were primarily the result of non-cash impairment charges in unproved properties of $8 million, $6 million of charges related to dry hole expense and $6 million of geological and geophysical expense.

General and Administrative Expenses

	Successor	
	Year Ended December 31,	
	2023	2022
Total G&A, net	$ 127	$ 142
G&A, net per Mcfe	$ 0.09	$ 0.10

Total general and administrative expenses, net during the 2023 Successor Period decreased $15 million compared to the 2022 Successor Period, primarily due to a decrease in compensation and other corporate expenses.

Separation and Other Termination Costs

During both the 2023 and 2022 Successor Periods, we recognized $5 million of separation and other termination costs related to one-time termination benefits for certain employees.

Depreciation, Depletion and Amortization

	Successor	
	Year Ended December 31,	
	2023	2022
DD&A	$ 1,527	$ 1,753
DD&A per Mcfe	$ 1.14	$ 1.20

The absolute and per Mcfe decreases in depreciation, depletion and amortization for the 2023 Successor Period compared to the 2022 Successor Period are primarily related to our Eagle Ford divestitures.

Other Operating Expense, Net

	Successor	
	Year Ended December 31,	
	2023	2022
Other operating expense, net	$ 18	$ 49

During the 2022 Successor Period, we recognized approximately $41 million of costs related to our Marcellus Acquisition, which included integration costs, consulting fees, financial advisory fees, legal fees and change in control expense in accordance with Chief's existing employment agreements.

Interest Expense

	Successor	
	Year Ended December 31,	
	2023	2022
Interest expense on debt	$ 143	$ 181
Other	—	13
Amortization of premium, issuance costs and other	(9)	(3)
Capitalized interest	(30)	(31)
Total interest expense	$ 104	$ 160

The decrease in total interest expense in the 2023 Successor Period compared to the 2022 Successor Period, was primarily due to lower average debt outstanding during the 2023 Successor Period. Additionally, $12 million of interest expense was recorded during the 2022 Successor Period pertaining to a tax interest assessment.

Other Income

	Successor	
	Year Ended December 31,	
	2023	2022
Other income	$ 79	$ 36

The increase in other income during the 2023 Successor Period compared to the 2022 Successor Period was primarily due to a $28 million increase in interest income, related to our higher average cash balance during the 2023 Successor Period, as well as a $24 million increase in deferred consideration amortization.

Income Tax Expense (Benefit)

We recorded income tax expense of $698 million in the 2023 Successor Period. Of this amount, $270 million is related to current federal and state income taxes, and the remainder is related to deferred federal and state income taxes. We recorded an income tax benefit of $1.3 billion in the 2022 Successor Period. Of the $1.3 billion of income tax benefit recorded in the 2022 Successor Period, $1.4 billion is related to the partial release of the valuation allowance, which is partially offset by $47 million in current federal and state income taxes. See Note 11 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a discussion of income tax expense (benefit).

Year ended December 31, 2022 compared to the period from February 10, 2021 through December 31, 2021

Below is a discussion of changes in our results of operations for the 2022 Successor Period compared to the 2021 Successor Period. Additionally, information is provided for the 2021 Predecessor Period. However, we are not able to compare the 40 days from January 1, 2021 through February 9, 2021 operating results to any previous periods reported in the consolidated financial statements and do not believe reviewing this period in isolation would be useful in identifying any trend in, or reaching any conclusions regarding, our overall operating performance.

Natural Gas, Oil and NGL Production and Average Sales Prices

	Successor							
	Year Ended December 31, 2022							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,836	6.03	—	—	—	—	1,836	6.03
Haynesville	1,611	5.92	—	—	—	—	1,611	5.92
Eagle Ford	127	5.64	51	96.10	16	36.76	529	11.76
Powder River Basin	10	5.45	2	95.18	1	53.96	26	10.66
Total	3,584	5.96	53	96.07	17	37.48	4,002	6.77
Average NYMEX Price		6.64		94.23				
Average Realized Price (including realized derivatives)		3.67		66.36		37.48		4.32

	Successor							
	Period from February 10, 2021 through December 31, 2021							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,296	3.25	—	—	—	—	1,296	3.25
Haynesville	750	4.10	—	—	—	—	750	4.10
Eagle Ford	137	4.02	60	69.25	19	29.76	608	8.65
Powder River Basin	53	4.33	9	67.90	3	40.00	129	7.69
Total	2,236	3.61	69	69.07	22	31.37	2,783	4.87
Average NYMEX Price		3.97		69.35				
Average Realized Price (including realized derivatives)		2.62		49.06		31.42		3.57

	Predecessor							
	Period from January 1, 2021 through February 9, 2021							
	Natural Gas		Oil		NGL		Total	
	MMcf per day	$/Mcf	MBbl per day	$/Bbl	MBbl per day	$/Bbl	MMcfe per day	$/Mcfe
Marcellus	1,233	2.42	—	—	—	—	1,233	2.42
Haynesville	543	2.44	—	—	—	—	543	2.44
Eagle Ford	165	2.57	74	53.37	18	23.94	721	6.71
Powder River Basin	61	2.92	10	51.96	4	34.31	144	5.71
Total	2,002	2.45	84	53.21	22	25.92	2,641	3.77
Average NYMEX Price		2.47		52.10				
Average Realized Price (including realized derivatives)		2.52		46.85		25.55		3.65

Natural Gas, Oil and NGL Sales

	Successor			
	Year Ended December 31, 2022			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 4,041	$ —	$ —	$ 4,041
Haynesville	3,481	—	—	3,481
Eagle Ford	261	1,798	212	2,271
Powder River Basin	20	66	13	99
Total natural gas, oil and NGL sales	$ 7,803	$ 1,864	$ 225	$ 9,892

	Successor			
	Period from February 10, 2021 through December 31, 2021			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 1,370	$ —	$ —	$ 1,370
Haynesville	998	—	—	998
Eagle Ford	179	1,354	179	1,712
Powder River Basin	75	202	44	321
Total natural gas, oil and NGL sales	$ 2,622	$ 1,556	$ 223	$ 4,401

	Predecessor			
	Period from January 1, 2021 through February 9, 2021			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 119	$ —	$ —	$ 119
Haynesville	53	—	—	53
Eagle Ford	17	159	17	193
Powder River Basin	7	20	6	33
Total natural gas, oil and NGL sales	$ 196	$ 179	$ 23	$ 398

Natural gas, oil and NGL sales in the 2022 Successor Period increased $5.49 billion compared to the 2021 Successor Period. The increase was attributable to a $2.343 billion increase in revenues from higher average prices received. Additionally, an increase of $3.147 billion was due to increased volumes in Marcellus and Haynesville, primarily due to the Marcellus Acquisition and the Vine Acquisition, respectively. These increases were partially offset by decreased volumes in Eagle Ford, which was primarily due to a natural decline in production, and the Powder River Basin, following the divestiture of the Powder River Basin assets in March 2022.

Production Expenses

	Successor				Predecessor	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 76	0.11	$ 34	0.08	$ 4	0.08
Haynesville	155	0.26	59	0.24	4	0.19
Eagle Ford	234	1.22	173	0.88	21	0.71
Powder River Basin	10	0.94	31	0.74	3	0.56
Total production expenses	$ 475	0.33	$ 297	0.33	$ 32	0.30

Production expenses in the 2022 Successor Period increased $178 million as compared to the 2021 Successor Period. The increase was primarily due to the Vine Acquisition in November 2021 and the Marcellus Acquisition in March 2022. The increase was partially offset by the divestiture of the Powder River Basin in March 2022.

Gathering, Processing and Transportation Expenses (“GP&T”)

	Successor				Predecessor	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 381	0.57	$ 287	0.68	$ 34	0.70
Haynesville	313	0.53	118	0.49	11	0.49
Eagle Ford	343	1.78	290	1.46	45	1.55
Powder River Basin	22	2.32	85	2.03	12	2.09
Total GP&T	$ 1,059	0.73	$ 780	0.86	$ 102	0.96

Gathering, processing and transportation expenses in the 2022 Successor Period increased $279 million compared to the 2021 Successor Period. Haynesville increased $195 million primarily due to the Vine Acquisition in November 2021. Marcellus increased $141 million, primarily due to the Marcellus Acquisition in March 2022, partially offset by a decrease of $47 million, primarily due to lower rates. Eagle Ford increased $53 million, primarily due to increased rates with higher commodity prices. Powder River Basin decreased by $63 million, primarily due to the divestiture in March 2022.

Severance and Ad Valorem Taxes

	Successor				Predecessor	
	Year Ended December 31, 2022		Period from February 10, 2021 through December 31, 2021		Period from January 1, 2021 through February 9, 2021	
		$/Mcfe		$/Mcfe		$/Mcfe
Marcellus	$ 17	0.03	$ 9	0.02	$ 1	0.01
Haynesville	75	0.13	22	0.09	2	0.09
Eagle Ford	139	0.71	96	0.48	13	0.45
Powder River Basin	11	1.09	31	0.75	2	0.48
Total severance and ad valorem taxes	$ 242	0.17	$ 158	0.17	$ 18	0.17

Severance and ad valorem taxes in the 2022 Successor Period increased $84 million as compared to the 2021 Successor Period. Higher commodity prices and increases to the Haynesville statutory severance tax rates in the 2022 Successor Period drove $58 million of the increase, and an additional $46 million increase was the result of the Vine Acquisition and Marcellus Acquisition. These increases were partially offset by a $20 million decrease attributable to the divestiture of the Powder River Basin in March 2022.

Natural Gas and Oil Derivatives

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Natural gas derivatives - realized gains (losses)	$ (2,998)	$ (715)	$ 6
Natural gas derivatives - unrealized gains (losses)	611	70	(179)
Total losses on natural gas derivatives	$ (2,387)	$ (645)	$ (173)
Oil derivatives - realized losses	$ (576)	$ (453)	$ (19)
Oil derivatives - unrealized gains (losses)	283	(29)	(190)
Total losses on oil derivatives	(293)	(482)	(209)
Total losses on natural gas and oil derivatives	$ (2,680)	$ (1,127)	$ (382)

See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a complete discussion of our derivative activity.

Marketing Revenues and Expenses

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Marketing revenues	$ 4,231	$ 2,263	$ 239
Marketing expenses	4,215	2,257	237
Marketing margin	$ 16	$ 6	$ 2

Marketing revenues and expenses increased in the 2022 Successor Period as a result of increased natural gas, oil and NGL prices received in our marketing operation. Additionally, during the 2022 Successor Period, marketing revenues and expenses increased due to increased volumes from the Vine Acquisition and Marcellus Acquisition.

Exploration Expenses

During the 2022 Successor Period, exploration expense charges of $23 million were primarily the result of non-cash impairment charges in unproved properties of $8 million, $6 million of charges related to dry hole expense and $6 million of geological and geophysical expense. We did not have material exploration expenses during the 2021 Successor Period or 2021 Predecessor Period.

General and Administrative Expenses

	Successor		Predecessor
	Year Ended December 31, 2022	**Period from February 10, 2021 through December 31, 2021**	**Period from January 1, 2021 through February 9, 2021**
Total G&A, net	$ 142	$ 97	$ 21
G&A, net per Mcfe	$ 0.10	$ 0.11	$ 0.20

Total general and administrative expenses, net during the 2022 Successor Period increased $45 million compared to the 2021 Successor Period due to adjustments in employee benefits and increases in transaction-related fees, as well as increases in other corporate expenses.

Separation and Other Termination Costs

During the 2022 Successor Period, 2021 Successor Period and 2021 Predecessor Period, we recognized $5 million, $11 million and $22 million, respectively, of separation and other termination costs related to one-time termination benefits for certain employees.

Depreciation, Depletion and Amortization

	Successor		Predecessor
	Year Ended December 31, 2022	**Period from February 10, 2021 through December 31, 2021**	**Period from January 1, 2021 through February 9, 2021**
DD&A	$ 1,753	$ 919	$ 72
DD&A per Mcfe	$ 1.20	$ 1.02	$ 0.68

The increase in depreciation, depletion and amortization for the 2022 Successor Period compared to the 2021 Successor Period is primarily the result of the Vine Acquisition and Marcellus Acquisition.

Other Operating Expense (Income), Net

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Other operating expense (income), net	$ 49	$ 84	$ (12)

During the 2022 Successor Period, we recognized approximately $41 million of costs related to our Marcellus Acquisition, which included integration costs, consulting fees, financial advisory fees, legal fees and change in control expense in accordance with Chief's existing employment agreements. In the 2021 Successor Period we recognized approximately $59 million of costs related to the Vine Acquisition, which included consulting fees, financial advisory fees and legal fees. Additionally, we recognized approximately $36 million of severance expense as a result of the Vine Acquisition, which included $15 million of cash severance and $21 million of non-cash severance, primarily related to the issuance of New Common Stock for the acceleration of certain Vine restricted stock unit awards. A majority of Vine executives and employees were terminated on the date the Vine Acquisition was completed. These executives and employees were entitled to severance benefits in accordance with existing employment agreements.

Interest Expense

	Successor		Predecessor
	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Interest expense on debt	$ 181	$ 79	$ 11
Other	13	—	—
Amortization of premium, issuance costs and other	(3)	5	—
Capitalized interest	(31)	(11)	—
Total interest expense	$ 160	$ 73	$ 11

The increase in total interest expense in the 2022 Successor Period compared to the 2021 Successor Period was primarily due to the increase in outstanding debt obligations between periods. In November 2021, we assumed Vine's $950 million of senior notes as part of the Vine Acquisition, and during the 2022 Successor Period, we had increased borrowings under our various credit agreements, compared to the 2021 Successor Period. During the 2022 Successor Period, borrowings under our credit agreements had an average interest rate of 8.7%. Additionally, $12 million of interest expense was recorded during the 2022 Successor Period pertaining to a tax interest assessment.

Reorganization Items, Net

	Predecessor	
	Period from January 1, 2021 through February 9, 2021	
Gains on the settlement of liabilities subject to compromise	$	6,443
Accrual for allowed claims		(1,002)
Gain on fresh start adjustments		201
Gain from release of commitment liabilities		55
Professional service provider fees and other		(60)
Success fees for professional service providers		(38)
Surrender of other receivable		(18)
FLLO alternative transaction fee		(12)
Total reorganization items, net	$	5,569

In the 2021 Predecessor Period, we recorded a net gain of $5.569 billion in reorganization items, net related to the Chapter 11 Cases. See Note 2 and Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a discussion of the Chapter 11 Cases and for discussion of adoption of fresh start accounting. We did not have any reorganization items, net for the 2022 Successor Period or the 2021 Successor Period.

Income Tax Expense (Benefit). We recorded an income tax benefit of $1.3 billion in the 2022 Successor Period. In the 2021 Successor and Predecessor Periods, we recorded an income tax benefit of $49 million and $57 million, respectively. Of the $1.3 billion of income tax benefit recorded in the 2022 Successor Period, $1.4 billion is related to the partial release of the valuation allowance, which is partially offset by $47 million in current federal and state income taxes. The income tax benefit recorded in the 2021 Successor Period is related to a $49 million partial release of the valuation allowance maintained against our net deferred tax asset position. The partial release was a consequence of recording a net deferred tax liability of $49 million resulting from the business combination accounting for Vine. The $57 million income tax benefit for the 2021 Predecessor Period consists of the removal of the income tax effects in other comprehensive income related to hedging settlements due to the fair value adjustments made upon emergence from bankruptcy. See Note 11 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a discussion of income tax expense (benefit).

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions that involve a significant level of estimation uncertainty and have or are reasonably likely to have a material impact on our financial condition or results of operations are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

Natural Gas and Oil Reserves. Estimates of natural gas and oil reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates. See *Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities* included in Item 8 of Part II of this report for further information.

Accounting for Business Combinations. We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 – Business Combinations and involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based on the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess, if any, of the consideration given to acquire an entity over the net amounts assigned to its assets acquired and liabilities assumed is recognized as goodwill. The excess, if any, of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity is recognized immediately to earnings as a gain from bargain purchase.

The Company's principal assets are its natural gas and oil properties, which are accounted for under the successful efforts accounting method. The Company determines the fair value of acquired natural gas and oil properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area are prepared using the estimated future revenues and operating costs for all proved developed properties and undeveloped properties comprising the proved and unproved reserves. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and (v) a market-based weighted average cost of capital by operating area. The Company utilizes NYMEX strip pricing, adjusted for differentials, to value the reserves. The NYMEX strip pricing inputs used are classified as Level 1 fair value assumptions and all other inputs are classified as Level 3 fair value assumptions. The discount rates utilized are derived using a weighted average cost of capital computation, which includes an estimated cost of debt and equity for market participants with similar geographies and asset development type by operating area.

Income Taxes. Income taxes are accounted for using the asset and liability method as required by GAAP. Deferred tax assets and liabilities arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets for tax attributes such as NOL carryforwards and disallowed business interest carryforwards are also recognized. Deferred tax assets represent potential future tax benefits and are reduced by a valuation allowance if it is more likely than not that such benefits will not be realized.

In assessing the need for a valuation allowance or adjustments to existing valuation allowances, one source of evidence is a projection of income exclusive of existing timing differences.

Our judgement regarding the realizability of deferred tax assets is thus partially affected by estimates of future financial condition.

We also routinely assess potential uncertain tax positions and, if required, establish accruals for such positions. Accounting guidance for recognizing and measuring uncertain tax positions requires that a more likely than not threshold condition be met on a tax position, based solely on its technical merits of being sustained, before any benefit of the uncertain tax position can be recognized in the financial statements. If it is more likely than not a tax position will be sustained, we measure and recognize the position following a cumulative probability estimate.

Impairments. Long-lived assets used in operations, including proved gas and oil properties, are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If there is an indication the carrying amount of an asset may not be recovered, the asset is assessed by management through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value by discounting using a weighted average cost of capital. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is assessed by management using the income approach. Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include our estimate of future natural gas and crude oil prices, production costs, development expenditures, anticipated production of proved reserves and other relevant data. Additionally, we utilize NYMEX strip pricing, adjusted for differentials, to value the reserves.

Reorganization and Fresh Start Accounting. Effective June 28, 2020, as a result of the filing of the Chapter 11 Cases we began accounting and reporting according to FASB ASC Topic 852 – Reorganizations ("ASC 852"), which specifies the accounting and financial reporting requirements for entities reorganizing through Chapter 11 bankruptcy proceedings. These requirements include distinguishing and presenting transactions associated with the reorganization and implementation of the plan of reorganization separately from activities related to ongoing operations of the business. Additionally, upon emergence from the Chapter 11 Cases, ASC 852 required us to allocate our reorganization value to our individual assets based on their estimated fair values, resulting in a new entity for financial reporting purposes. After the Effective Date, the accounting and reporting requirements of ASC 852 are no longer applicable and have no impact on the Successor periods.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to our risk of loss arising from adverse changes in natural gas, oil and NGL prices and interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Price Risk

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL, which have historically been volatile. To mitigate a portion of our exposure to adverse price changes, we enter into various derivative instruments. Our natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil and NGL, allow us to predict with greater certainty the revenue we will receive. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

We determine the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our commodity hedging arrangements that require counterparties to post collateral if their obligations to us are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of the fair value measurements associated with our derivatives.

For the 2023 Successor Period, natural gas, oil and NGL revenues, excluding any effect of our derivative instruments, were $2,853 million, $596 million, and $98 million, respectively. Based on production, natural gas, oil and NGL revenue for the 2023 Successor Period would have increased or decreased by approximately $285 million, $60 million, and $10 million, respectively, for each 10% increase or decrease in prices. As of December 31, 2023, the fair value of our natural gas derivatives was a net asset of $687 million. As of December 31, 2023, we did not have any open oil or NGL derivative positions. A 10% increase in forward natural gas prices would decrease the valuation of natural gas derivatives by approximately $188 million, while a 10% decrease would increase the valuation by $191 million. This fair value change assumes volatility based on prevailing market parameters at December 31, 2023. Additionally, should oil prices not meet the average target prices specified with the contingent payment from SilverBow, we may not receive any payment from the up to $50 million contingent consideration arrangement. See Note 15 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further information on our open derivative positions, including information about the contingent consideration arrangement.

Interest Rate Risk

Our exposure to interest rate changes relates primarily to borrowings under our New Credit Facility for the 2023 Successor Period, our New Credit Facility and Exit Credit Facility for the 2022 Successor Period, the Exit Credit Facility for the 2021 Successor Period and the DIP Facility for the 2021 Predecessor Period. Interest is payable on borrowings under each respective credit facility based on floating rates. See Note 6 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information. As of December 31, 2023, we did not have any outstanding borrowings under our New Credit Facility.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chesapeake Energy Corporation and its subsidiaries (Successor) (the "Company") as of December 31, 2023 and 2022, and the related consolidated statements of operations, of comprehensive income, of stockholders' equity and of cash flows for the years then ended and for the period from February 10, 2021 through December 31, 2021, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for the years then ended and for the period from February 10, 2021 through December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis of Accounting

As discussed in Note 2 to the consolidated financial statements, Chesapeake Energy Corporation and certain of its subsidiaries (collectively the "Debtors") filed voluntary petitions on June 28, 2020 with the United States Bankruptcy Court for the Southern District of Texas for relief under the provisions of Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Debtors' joint plan of reorganization on January 16, 2021 and the Debtors emerged from bankruptcy on February 9, 2021. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting as of February 9, 2021.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated 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.

The Impact of Proved Natural Gas and Oil Reserves on Proved Natural Gas and Oil Properties, Net

As described in Note 1 to the consolidated financial statements, the Company's property and equipment, net balance was approximately $10.1 billion as of December 31, 2023, and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2023 was approximately $1.5 billion, both of which substantially related to proved natural gas and oil properties. The Company follows the successful efforts method of accounting for its natural gas and oil properties. Under this method, all capitalized well costs and leasehold costs of proved natural gas and oil properties are depreciated by the units-of-production (UOP) method based on total estimated proved developed reserves and proved reserves, respectively. As disclosed by management, estimates of natural gas and oil reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of management's estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves volumes may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. The estimates of proved natural gas and oil reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the impact of proved natural gas and oil reserves on proved natural gas and oil properties, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved natural gas and oil reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved natural gas and oil reserves volumes and the assumptions applied to the data related to the commodity pricing differentials and future development costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved natural gas and oil reserves. The work of management's specialists was used in performing procedures to evaluate the reasonableness of the proved natural gas and oil reserves volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluating the methods and assumptions used by the specialists, testing the completeness and accuracy of data used by the specialists, and evaluating the specialists' findings. These procedures also included, among others, testing the completeness and accuracy of data related to commodity pricing differentials and future development costs. Additionally, these procedures included evaluating whether the assumptions applied to the aforementioned data were reasonable considering the past performance of the Company.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 21, 2024

We have served as the Company's auditor since 1992.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of operations, of comprehensive income, of stockholders' equity and of cash flows of Chesapeake Energy Corporation and its subsidiaries (Predecessor) (the "Company") for the period from January 1, 2021 through February 9, 2021, including 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 results of operations and cash flows of the Company for the period from January 1, 2021 through February 9, 2021 in conformity with accounting principles generally accepted in the United States of America.

Basis of Accounting

As discussed in Note 2 to the consolidated financial statements, Chesapeake Energy Corporation and certain of its subsidiaries (collectively the "Debtors") filed voluntary petitions on June 28, 2020 with the United States Bankruptcy Court for the Southern District of Texas for relief under the provisions of Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Debtors' joint plan of reorganization on January 16, 2021 and the Debtors emerged from bankruptcy on February 9, 2021. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting.

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 audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 of these consolidated financial statements 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 consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 24, 2022

We have served as the Company's auditor since 1992.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Successor	
($ in millions, except per share data)	**December 31, 2023**	**December 31, 2022**
Assets		
Current assets:		
Cash and cash equivalents	$ 1,079	$ 130
Restricted cash	74	62
Accounts receivable, net	593	1,438
Short-term derivative assets	637	34
Assets held for sale	—	819
Other current assets	226	215
Total current assets	2,609	2,698
Property and equipment:		
Natural gas and oil properties, successful efforts method		
Proved natural gas and oil properties	11,468	11,096
Unproved properties	1,806	2,022
Other property and equipment	497	500
Total property and equipment	13,771	13,618
Less: accumulated depreciation, depletion and amortization	(3,674)	(2,431)
Total property and equipment, net	10,097	11,187
Long-term derivative assets	74	47
Deferred income tax assets	933	1,351
Other long-term assets	663	185
Total assets	$ 14,376	$ 15,468
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 425	$ 603
Accrued interest	39	42
Short-term derivative liabilities	3	432
Other current liabilities	847	1,627
Total current liabilities	1,314	2,704
Long-term debt, net	2,028	3,093
Long-term derivative liabilities	9	174
Asset retirement obligations, net of current portion	265	323
Other long-term liabilities	31	50
Total liabilities	3,647	6,344
Contingencies and commitments (Note 7)		
Stockholders' equity:		
Common stock, $0.01 par value, 450,000,000 shares authorized: 130,789,936 and 134,715,094 shares issued	1	1
Additional paid-in capital	5,754	5,724
Retained earnings	4,974	3,399
Total stockholders' equity	10,729	9,124
Total liabilities and stockholders' equity	$ 14,376	$ 15,468

The accompanying notes are an integral part of these consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

($ in millions except per share data)	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Revenues and other:				
Natural gas, oil and NGL	$ 3,547	$ 9,892	$ 4,401	$ 398
Marketing	2,500	4,231	2,263	239
Natural gas and oil derivatives	1,728	(2,680)	(1,127)	(382)
Gains on sales of assets	946	300	12	5
Total revenues and other	8,721	11,743	5,549	260
Operating expenses:				
Production	356	475	297	32
Gathering, processing and transportation	853	1,059	780	102
Severance and ad valorem taxes	167	242	158	18
Exploration	27	23	7	2
Marketing	2,499	4,215	2,257	237
General and administrative	127	142	97	21
Separation and other termination costs	5	5	11	22
Depreciation, depletion and amortization	1,527	1,753	919	72
Impairments	—	—	1	—
Other operating expense (income), net	18	49	84	(12)
Total operating expenses	5,579	7,963	4,611	494
Income (loss) from operations	3,142	3,780	938	(234)
Other income (expense):				
Interest expense	(104)	(160)	(73)	(11)
Losses on purchases, exchanges or extinguishments of debt	—	(5)	—	—
Other income	79	36	31	2
Reorganization items, net	—	—	—	5,569
Total other income (expense)	(25)	(129)	(42)	5,560
Income before income taxes	3,117	3,651	896	5,326
Income tax expense (benefit)	698	(1,285)	(49)	(57)
Net income	2,419	4,936	945	5,383
Deemed dividend on warrants	—	(67)	—	—
Net income available to common stockholders	$ 2,419	$ 4,869	$ 945	$ 5,383
Earnings per common share:				
Basic	$ 18.21	$ 38.71	$ 9.29	$ 550.35
Diluted	$ 16.92	$ 33.36	$ 8.12	$ 534.51
Weighted average common shares outstanding (in thousands):				
Basic	132,840	125,785	101,754	9,781
Diluted	142,976	145,961	116,341	10,071

The accompanying notes are an integral part of these consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Successor			Predecessor
($ in millions)	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Net income	$ 2,419	$ 4,936	$ 945	$ 5,383
Other comprehensive income, net of income tax:				
Reclassification of losses on settled derivative instruments[(a)]	—	—	—	3
Other comprehensive income	—	—	—	3
Comprehensive income	$ 2,419	$ 4,936	$ 945	$ 5,386

(a) Deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

($ in millions)	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Cash flows from operating activities:				
Net income	$ 2,419	$ 4,936	$ 945	$ 5,383
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	1,527	1,753	919	72
Deferred income tax expense (benefit)	428	(1,332)	(49)	(57)
Derivative (gains) losses, net	(1,728)	2,680	1,127	382
Cash receipts (payments) on derivative settlements, net	354	(3,561)	(1,142)	(17)
Share-based compensation	33	22	9	3
Gains on sales of assets	(946)	(300)	(12)	(5)
Impairments	—	—	1	—
Non-cash reorganization items, net	—	—	—	(6,680)
Exploration	12	14	2	2
Losses on purchases, exchanges or extinguishments of debt	—	5	—	—
Other	6	31	46	45
Changes in assets and liabilities	275	(123)	(37)	851
Net cash provided by (used in) operating activities	2,380	4,125	1,809	(21)
Cash flows from investing activities:				
Capital expenditures	(1,829)	(1,823)	(669)	(66)
Business combination, net	—	(1,967)	(194)	—
Contributions to investments	(231)	(18)	—	—
Proceeds from divestitures of property and equipment	2,533	407	13	—
Net cash provided by (used in) investing activities	473	(3,401)	(850)	(66)
Cash flows from financing activities:				
Proceeds from New Credit Facility	1,125	1,600	—	—
Payments on New Credit Facility	(2,175)	(550)	—	—
Proceeds from Exit Credit Facility	—	9,583	30	—
Payments on Exit Credit Facility	—	(9,804)	(80)	(479)
Payments on DIP Facility borrowings	—	—	—	(1,179)
Proceeds from issuance of senior notes, net	—	—	—	1,000
Proceeds from issuance of common stock	—	—	—	600
Proceeds from warrant exercise	—	27	2	—
Debt issuance and other financing costs	—	(17)	(3)	(8)
Cash paid to repurchase and retire common stock	(355)	(1,073)	—	—
Cash paid for common stock dividends	(487)	(1,212)	(119)	—
Other	—	—	(1)	—
Net cash used in financing activities	(1,892)	(1,446)	(171)	(66)
Net increase (decrease) in cash, cash equivalents and restricted cash	961	(722)	788	(153)
Cash, cash equivalents and restricted cash, beginning of period	192	914	126	279
Cash, cash equivalents and restricted cash, end of period	$ 1,153	$ 192	$ 914	$ 126

The accompanying notes are an integral part of these consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS – (Continued)

($ in millions)	Successor Year Ended December 31, 2023	Successor Year Ended December 31, 2022	Successor Period from February 10, 2021 through December 31, 2021	Predecessor Period from January 1, 2021 through February 9, 2021
Cash and cash equivalents	$ 1,079	$ 130	$ 905	$ 40
Restricted cash	74	62	9	86
Total cash, cash equivalents and restricted cash	$ 1,153	$ 192	$ 914	$ 126

Supplemental disclosures to the consolidated statements of cash flows are presented below:

($ in millions)	Successor Year Ended December 31, 2023	Successor Year Ended December 31, 2022	Successor Period from February 10, 2021 through December 31, 2021	Predecessor Period from January 1, 2021 through February 9, 2021
Supplemental cash flow information:				
Cash paid for reorganization items, net	$ —	$ —	$ 65	$ 66
Interest paid, net of capitalized interest	$ 117	$ 146	$ 34	$ 13
Income taxes paid (refunds received), net	$ 132	$ 193	$ (9)	$ —
Supplemental disclosure of significant non-cash investing and financing activities:				
Change in accrued drilling and completion costs	$ (31)	$ 148	$ 30	$ (5)
Put option premium on equity backstop agreement	$ —	$ —	$ —	$ 60
Common stock issued for business combination	$ —	$ 764	$ 1,232	$ —
Operating lease obligations recognized	$ 96	$ 120	$ —	$ —

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

($ in millions)	Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Total Stockholders' Equity (Deficit)
	Shares	Amount	Shares	Amount				
Balance as of February 10, 2021 (Successor)	—	$ —	97,907,081	$ 1	$ 3,585	$ —	$ —	$ 3,586
Share-based compensation	—	—	248,487	—	21	—	—	21
Issuance of common stock for Vine Acquisition	—	—	18,709,399	—	1,237	—	—	1,237
Issuance of common stock for warrant exercise	—	—	188,292	—	2	—	—	2
Issuance of reserved common stock and warrants	—	—	864,090	—	—	—	—	—
Net income	—	—	—	—	—	945	—	945
Dividends on common stock	—	—	—		—	(120)	—	(120)
Balance as of December 31, 2021 (Successor)	—	$ —	117,917,349	$ 1	$ 4,845	$ 825	$ —	$ 5,671
Issuance of common stock for Marcellus Acquisition	—	—	9,442,185	—	764	—	—	764
Share-based compensation	—	—	174,740	—	21	—	—	21
Issuance of common stock for warrant exchange offer	—	—	16,305,984	—	67	—	—	67
Issuance of common stock for warrant exercise	—	—	2,102,244	—	27	—	—	27
Issuance of reserved common stock and warrants	—	—	439,370	—	—	—	—	—
Repurchase and retirement of common stock	—	—	(11,666,778)	—	—	(1,073)	—	(1,073)
Net income	—	—	—	—	—	4,936	—	4,936
Dividends on common stock	—	—	—	—	—	(1,222)	—	(1,222)
Deemed dividend on warrants	—	—	—	—	—	(67)	—	(67)
Balance as of December 31, 2022 (Successor)	—	$ —	134,715,094	$ 1	$ 5,724	$ 3,399	$ —	$ 9,124
Share-based compensation	—	—	214,684	—	31	—	—	31
Issuance of common stock for warrant exercise	—	—	221,952	—	—	—	—	—
Issuance of reserved common stock and warrants	—	—	12,089	—	—	—	—	—
Repurchase and retirement of common stock	—	—	(4,373,883)	—	(1)	(357)	—	(358)
Net income	—	—	—	—	—	2,419	—	2,419
Dividends on common stock	—	—	—	—	—	(487)	—	(487)
Balance as of December 31, 2023 (Successor)	—	$ —	130,789,936	$ 1	$ 5,754	$ 4,974	$ —	$ 10,729

The accompanying notes are an integral part of these consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY - (Continued)

	Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Total Stockholders' Equity (Deficit)
($ in millions)	Shares	Amount	Shares	Amount				
Balance as of December 31, 2020 (Predecessor)	5,563,358	$ 1,631	9,780,547	$ —	$ 16,937	$ (23,954)	$ 45	$ (5,341)
Share-based compensation	—	—	67	—	3	—	—	3
Hedging activity	—	—	—	—	—	—	3	3
Net income	—	—	—	—	—	5,383	—	5,383
Cancellation of Predecessor equity	(5,563,358)	(1,631)	(9,780,614)	—	(16,940)	18,571	(48)	(48)
Issuance of Successor common stock	—	—	97,907,081	1	3,330	—	—	3,331
Issuance of Successor Class A warrants	—	—	—	—	93	—	—	93
Issuance of Successor Class B warrants	—	—	—	—	94	—	—	94
Issuance of Successor Class C warrants	—	—	—	—	68	—	—	68
Balance as of February 9, 2021 (Predecessor)	—	$ —	97,907,081	$ 1	$ 3,585	$ —	$ —	$ 3,586

The accompanying notes are an integral part of these consolidated financial statements.

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake," “we,” “our,” “us” or the "Company") is a natural gas and oil exploration and production company engaged in the acquisition, exploration and development of properties for the production of natural gas, oil and NGL from underground reservoirs. Our operations are located onshore in the United States. As discussed in Note 2 below, we filed the Chapter 11 Cases on the Petition Date and subsequently operated as a debtor-in-possession, in accordance with applicable provisions of the Bankruptcy Code, until emergence on February 9, 2021. To facilitate our financial statement presentations, we refer to the post-emergence reorganized Company in these consolidated financial statements and footnotes as the “Successor” for periods subsequent to February 9, 2021, and to the pre-emergence Company as “Predecessor” for the period on or prior to February 9, 2021.

Basis of Presentation

The accompanying consolidated financial statements of Chesapeake were prepared in accordance with GAAP and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated. All monetary values, other than per unit and per share amounts, are stated in millions of U.S. dollars unless otherwise specified.

This Annual Report on Form 10-K (this “Form 10-K”) relates to the financial position of the Successor as of December 31, 2023 and as of December 31, 2022, and the year ended December 31, 2023 (“2023 Successor Period”), the year ended December 31, 2022 (“2022 Successor Period”), the period of February 10, 2021 through December 31, 2021 (“2021 Successor Period”) and the period of January 1, 2021 through February 9, 2021 (“2021 Predecessor Period”).

Accounting During Bankruptcy

We have applied Accounting Standards Codification (ASC) 852, *Reorganizations,* in preparing the consolidated financial statements. ASC 852 requires that the financial statements, for periods subsequent to the filing of a petition of Chapter 11 Cases, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that were realized or incurred during the bankruptcy proceedings, including losses related to executory contracts that were approved for rejection by the Bankruptcy Court, and unamortized debt issuance costs, premiums and discounts associated with debt classified as liabilities subject to compromise, are recorded as reorganization items, net on our accompanying consolidated statements of operations. See Note 2 for more information regarding reorganization items.

Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the related disclosures in the financial statements. Management evaluates its estimates and related assumptions regularly, including those related to the impairment of natural gas and oil properties, natural gas and oil reserves, derivatives, income taxes, impairment of other property and equipment, environmental remediation costs, asset retirement obligations, litigation and regulatory proceedings and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ significantly from these estimates.

Consolidation

We consolidate entities in which we have a controlling financial interest and variable interest entities in which we are the primary beneficiary. We consolidate subsidiaries in which we hold, directly or indirectly, more than 50% of the voting rights. We use the equity method of accounting to record our net interests where we have the ability to exercise significant influence through our investment but lack a controlling financial interest. Under the equity method, our share of net income (loss) is included in our consolidated statements of operations according to our equity ownership or according to the terms of the applicable governing instrument. See Note 18 for further discussion of our investments. Undivided interests in natural gas and oil properties are consolidated on a proportionate basis.

Segments

Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker, who is our Chief Executive Officer, for the purpose of allocating an enterprise's resources and assessing its operating performance. We have concluded that we have only one reportable operating segment, due to the similar nature of the exploration and production business across Chesapeake and its consolidated subsidiaries and the fact that our marketing activities are ancillary to our operations.

Cash and Cash Equivalents

For purposes of the consolidated financial statements, we consider investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents.

Restricted Cash

As of December 31, 2023, we had restricted cash of $74 million. Our restricted cash represents funds legally restricted for payment of certain convenience class unsecured claims following our emergence from bankruptcy, as well as for future payment of certain royalties.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables that we believe may be uncollectible. See Note 10 for additional information regarding our accounts receivable.

Natural Gas and Oil Properties

We follow the successful efforts method of accounting for our natural gas and oil properties. Under this method, exploration costs such as exploratory geological and geophysical costs, expiration of unproved leasehold, delay rentals and exploration overhead are expensed as incurred. All costs related to production, general corporate overhead and similar activities are also expensed as incurred. All property acquisition costs and development costs are capitalized when incurred.

Exploratory drilling costs are initially capitalized, or suspended, pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. Costs of unsuccessful wells are charged to exploration expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If we determine that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. We review the status of all suspended exploratory drilling costs quarterly. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of natural gas and oil are capitalized.

Costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depreciated using the unit-of-production ("UOP") method based on total estimated proved developed gas and oil reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves.

Proceeds from the sales of individual natural gas and oil properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depreciation, depletion and amortization, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recognized until an entire amortization base is sold. However, a gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

When circumstances indicate that the carrying value of proved natural gas and oil properties may not be recoverable, we compare unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on our estimate of future natural gas and crude oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820, *Fair Value Measurements*. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of commodity prices, pricing adjustments for differentials, operating costs, capital investment plans, future production volumes, and estimated proved reserves, considering all available information at the date of review. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a market-based weighted average cost of capital. We have classified these fair value measurements as Level 3 in the fair value hierarchy.

Other Property and Equipment

Other property and equipment consists primarily of buildings and improvements, computers and office equipment, land and other assets that support our operations. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. Other property and equipment costs, excluding land, are depreciated on a straight-line basis and recorded within depreciation, depletion and amortization in the consolidated statement of operations.

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including any disposal value, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets and discounted cash flow. See Note 17 for further discussion of other property and equipment.

Assets Held for Sale

We may market certain non-core natural gas and oil assets or other properties for sale. At the end of each reporting period, we evaluate if these assets should be classified as held for sale. The held for sale criteria includes the following: management commits to a plan to sell, the asset is available for immediate sale, an active program to locate a buyer exists, the sale of the asset is probable and expected to be completed within a year, the asset is actively being marketed for sale and that it is unlikely that significant changes to the plan will be made. If each of the criteria are met, then the assets and associated liabilities are classified as held for sale. Additionally, once assets are classified as held for sale, we cease depreciation on those related assets. See Note 4 for further discussion.

Capitalized Interest

Interest from external borrowings is capitalized on significant investments in major development projects until the asset is ready for service using the weighted average borrowing rate of outstanding borrowings. Capitalized interest is determined by multiplying our weighted average borrowing cost on debt by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

Accounts Payable

Included in accounts payable as of December 31, 2022 are liabilities of approximately $150 million, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts.

Debt Issuance Costs

Costs associated with the arrangement of our credit facilities are included in other long-term assets and are amortized over the life of the facility using the straight-line method. As of December 31, 2023, these costs were $19 million. Upon the termination of the Exit Credit Facility, we recognized $5 million of losses on purchases, exchanges or extinguishment of debt during the 2022 Successor Period relating to lenders who had previously participated in the Exit Credit Facility that chose not to participate in the New Credit Facility. Costs associated with the issuance of the Successor senior notes are included in long-term debt and the remaining unamortized issuance costs are amortized over the life of the senior notes using the straight-line method. Unamortized issuance costs associated with the Successor senior notes as of December 31, 2023 totaled $5 million.

Litigation Contingencies

We are subject to litigation and regulatory proceedings, claims and liabilities that arise in the ordinary course of business. We accrue losses associated with litigation and regulatory claims when such losses are probable and reasonably estimable. If we determine that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, our best estimate within the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or third-party recoveries. Legal defense costs associated with loss contingencies are expensed in the period incurred. See Note 7 for further discussion of litigation contingencies.

Environmental Remediation Costs

We record environmental reserves for estimated remediation costs related to existing conditions from past operations when the responsibility to remediate is probable and the costs can be reasonably estimated. Expenditures that create future benefits or contribute to future revenue generation are capitalized. See Note 7 for discussion of environmental contingencies.

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our natural gas and oil properties. See Note 20 for further discussion of asset retirement obligations.

Revenue Recognition

Revenue from the sale of natural gas, oil and NGL is recognized upon the transfer of control of the products, which is typically when the products are delivered to customers. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration we expect to receive in exchange for those products.

Revenue from contracts with customers includes the sale of our natural gas, oil and NGL production (recorded as natural gas, oil and NGL revenues in the consolidated statements of operations) as well as the sale of certain of our joint interest holders' production which we purchase under joint operating arrangements (recorded in marketing revenues in the consolidated statements of operations). In connection with the marketing of these products, we obtain control of the natural gas, oil and NGL we purchase from other interest owners at defined delivery points and deliver the product to third parties, at which time revenues are recorded. See Note 10 for a presentation of the disaggregation of revenue.

Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30 days. There are no significant judgments that significantly affect the amount or timing of revenue from contracts with customers.

We also generate revenue from other sources, including from a variety of derivative and hedging activities to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility, as well as a variety of natural gas, oil and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and satisfaction of our pipeline delivery commitments (recorded within marketing revenues in the consolidated statements of operations). In circumstances where we act as an agent rather than a principal, our results of operations related to natural gas, oil and NGL marketing activities are presented on a net basis.

Fair Value Measurements

Certain financial instruments are reported on a recurring basis at fair value on our consolidated balance sheets. We also use fair value measurements on a nonrecurring basis when a qualitative assessment of our assets indicates a potential impairment. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments. See Notes 6 and 15 for further discussion of fair value measurements.

Derivatives

Derivative instruments are recorded at fair value, and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are followed. As of December 31, 2023, none of our open derivative instruments were designated as cash flow hedges.

Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next 12 months based on market prices/rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows. All of our commodity derivative instruments are subject to master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, as well as related cash collateral if applicable, by counterparty. Therefore, we net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. See Note 15 for further discussion of our derivative instruments.

Share-Based Compensation

Our share-based compensation program consists of restricted stock units and performance share units granted to employees and restricted stock units granted to non-employee directors under our Long Term Incentive Plan. We recognize the cost of services received in exchange for restricted stock units based on the fair value of the equity instruments as of the grant date. This value is amortized over the vesting period, which is generally three years from the grant date. Forfeitures on our share-based compensation awards are recognized as they occur. Because performance share units are settled in shares, they are classified as equity and are measured at fair value as of the grant date.

To the extent compensation expense relates to employees directly involved in the acquisition of natural gas and oil leasehold and development activities, these amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expense, production expense, or exploration expense, based on the employees involved in those activities. See Note 13 for further discussion of share-based compensation.

2. Chapter 11 Emergence

On June 28, 2020 (the “Petition Date”), the Debtors filed voluntary petitions for relief under the Bankruptcy Code in the Bankruptcy Court. On June 29, 2020, the Bankruptcy Court entered an order authorizing the joint administration of the Chapter 11 Cases under the caption *In re Chesapeake Energy Corporation*, Case No. 20-33233. The Non-Filing Entities were not part of the Chapter 11 Cases. The Debtors and the Non-Filing Entities continued to operate in the ordinary course of business during the Chapter 11 Cases.

The Bankruptcy Court confirmed the Plan in a bench ruling on January 13, 2021 and entered the Confirmation Order on January 16, 2021. The Debtors emerged from bankruptcy on February 9, 2021 (the “Effective Date”). The Company’s bankruptcy proceedings and related matters have been summarized below.

Debtor-In-Possession

During the pendency of the Chapter 11 Cases, we operated our business as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted the first day relief we requested that was designed primarily to mitigate the impact of the Chapter 11 Cases on our operations, vendors, suppliers, customers and employees. As a result, we were able to conduct normal business activities and pay all associated obligations for the period following the Petition Date and were also authorized to pay mineral interest owner royalties, employee wages and benefits, and certain vendors and suppliers in the ordinary course for goods and services provided prior to the Petition Date. During the pendency of the Chapter 11 Cases, all transactions outside the ordinary course of business required the prior approval of the Bankruptcy Court.

Automatic Stay

Subject to certain specific exceptions under the Bankruptcy Code, the filing of the Chapter 11 Cases automatically stayed all judicial or administrative actions against us and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. Absent an order from the Bankruptcy Court, substantially all of the Debtors' pre-petition liabilities were subject to compromise and discharge under the Bankruptcy Code. The automatic stay was lifted on the Effective Date.

Plan of Reorganization

In accordance with the Plan confirmed by the Bankruptcy Court, the following significant transactions occurred upon the Company's emergence from bankruptcy on February 9, 2021:

- On the Effective Date, we issued 97,907,081 shares of New Common Stock, reserved 2,092,918 shares of New Common Stock for future issuance to eligible holders of Allowed Unsecured Notes Claims and Allowed General Unsecured Claims and reserved 37,174,210 shares of New Common Stock for issuance upon exercise of the Warrants, which were the result of the transactions described below. We also entered into a registration rights agreement, warrant agreements and amended our articles of incorporation and bylaws for the authorization of the New Common Stock and to provide registration rights thereunder, among other corporate governance actions. See Note 12 for further discussion of our post-emergence equity.

- Each holder of an equity interest in the Predecessor, including the Predecessor's common and preferred stock, had such interest canceled, released, and extinguished without any distribution.

- Each holder of obligations under the pre-petition revolving credit facility received, at such holder's prior determined allocation, its pro rata share of either Tranche A Loans or Tranche B Loans, on a dollar for dollar basis.

- Each holder of obligations under the FLLO Term Loan Facility received its pro rata share of 23,022,420 shares of New Common Stock.

- Each holder of an Allowed Second Lien Notes Claim received its pro rata share of 3,635,118 shares of New Common Stock, 11,111,111 Class A Warrants to purchase 11,111,111 shares of New Common Stock, 12,345,679 Class B Warrants to purchase 12,345,679 shares of New Common Stock, and 6,858,710 Class C Warrants to purchase 6,858,710 shares of New Common Stock.

- Each holder of an Allowed Unsecured Notes Claim received its pro rata share of 1,311,089 shares of New Common Stock and 2,473,757 Class C Warrants to purchase 2,473,757 shares of New Common Stock.

- Each holder of an Allowed General Unsecured Claim received its pro rata share of 231,112 shares of New Common Stock and 436,060 Class C Warrants to purchase 436,060 shares of New Common Stock; provided that to the extent such Allowed General Unsecured Claim is a Convenience Claim, such holder instead received its pro rata share of $10 million, which pro rata share shall not exceed five percent of such Convenience Claim.

- Participants in the rights offering extending to the applicable classes under the Plan received 62,927,320 shares of New Common Stock.

- In connection with the rights offering described above, the Backstop Parties under the Backstop Commitment Agreement received 6,337,031 shares of New Common Stock in respect to the Put Option Premium, and 442,991 shares of New Common Stock were issued in connection with the backstop obligation thereunder to purchase unsubscribed shares of the New Common Stock.

- 2,092,918 shares of New Common Stock and 3,948,893 Class C Warrants were reserved for future issuance to eligible holders of Allowed Unsecured Notes Claims and Allowed General Unsecured Claims. The reserved New Common Stock and Class C Warrants will be issued on a pro rata basis upon the determination of the allowed portion of all disputed General Unsecured Claims and Unsecured Notes Claims.

- The 2021 Long Term Incentive Plan (the "LTIP") was approved with a share reserve equal to 6,800,000 shares of New Common Stock.

- Each holder of an Allowed Other Secured Claim will receive, at the Company's option and in consultation with the Required Consenting Stakeholders (as defined in the Plan): (a) payment in full in cash; (b) the collateral securing its secured claim; (c) reinstatement of its secured claim; or (d) such other treatment that renders its secured claim unimpaired in accordance with Section 1124 of the Bankruptcy Code.

- Each holder of an Allowed Other Priority Claim (as defined in the Plan) will receive cash up to the allowed amount of its claim.

Additionally, pursuant to the Plan confirmed by the Bankruptcy Court, the Company's post-emergence Board of Directors is comprised of seven directors, including the Company's Chief Executive Officer, Domenic J. Dell'Osso Jr., the Company's Chairman of the Board, Michael Wichterich, and five non-employee directors, Timothy S. Duncan, Benjamin C. Duster, IV, Sarah A. Emerson, Matthew M. Gallagher and Brian Steck.

3. Fresh Start Accounting

Fresh Start Accounting

In connection with our emergence from bankruptcy and in accordance with ASC 852, we qualified for and applied fresh start accounting on the Effective Date. We were required to apply fresh start accounting because (i) the holders of existing voting shares of the Company prior to its emergence received less than 50% of the voting shares of the Company outstanding following its emergence from bankruptcy and (ii) the reorganization value of our assets immediately prior to confirmation of the Plan of approximately $6.8 billion was less than the post-petition liabilities and allowed claims of $13.2 billion.

In accordance with ASC 852, with the application of fresh start accounting, the Company allocated its reorganization value to its individual assets based on their estimated fair value in conformity with FASB ASC Topic 820 - *Fair Value Measurements* and FASB ASC Topic 805 - *Business Combinations*. Accordingly, the consolidated financial statements after February 9, 2021 are not comparable with the consolidated financial statements as of or prior to that date. The Effective Date fair values of the Successor's assets and liabilities differ materially from their recorded values, as reflected on the historical balance sheet of the Predecessor.

Reorganization Value

Reorganization value is derived from an estimate of enterprise value, or fair value of the Company's interest-bearing debt and stockholders' equity. Under ASC 852, reorganization value generally approximates fair value of the entity before considering liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after the effects of a restructuring. As set forth in the disclosure statement, amended for updated pricing, and approved by the Bankruptcy Court, the enterprise value of the Successor was estimated to be between $3.5 billion and $4.9 billion. With the assistance of third-party valuation advisors, we determined the enterprise value and corresponding implied equity value of the Successor using various valuation approaches and methods, including: (i) income approach using a calculation of present value of future cash flows based on our financial projections, (ii) the market approach using selling prices of similar assets and (iii) the cost approach. For GAAP purposes, the Company valued the Successor's individual assets, liabilities and equity instruments and determined an estimate of the enterprise value within the estimated range. Management concluded that the best estimate of enterprise value was $4.85 billion. Specific valuation approaches and key assumptions used to arrive at reorganization value, and the value of discrete assets and liabilities resulting from the application of fresh start accounting, are described below in greater detail within the valuation process.

The enterprise value and corresponding implied equity value are dependent upon achieving the future financial results set forth in our valuation using an asset-based methodology of estimated proved reserves, undeveloped properties, and other financial information, considerations and projections, applying a combination of the income, cost and market approaches as of the fresh start reporting date of February 9, 2021. All estimates, assumptions, valuations and financial projections, including the fair value adjustments, the financial projections, the enterprise value and equity value projections, are inherently subject to significant uncertainties and the resolution of contingencies beyond our control. Accordingly, there is no assurance that the estimates, assumptions, valuations or financial projections will be realized, and actual results could vary materially.

The following table reconciles the enterprise value to the implied fair value of the Successor's equity as of the Effective Date:

	February 9, 2021
Enterprise Value	$ 4,851
Plus: Cash and cash equivalents[(a)]	48
Less: Fair value of debt	(1,313)
Successor equity value	$ 3,586

(a) Cash and cash equivalents includes $8 million that was initially classified as restricted cash as of the Effective Date but subsequently released from escrow and returned to the Successor. Restricted cash exclusive of the $8 million is not included in the table above.

The following table reconciles the enterprise value to the reorganization value as of the Effective Date:

	February 9, 2021
Enterprise value	$ 4,851
Plus: Cash and cash equivalents[(a)]	48
Plus: Current liabilities	1,582
Plus: Asset retirement obligations (non-current portion)	236
Plus: Other non-current liabilities	97
Reorganization value of Successor assets	$ 6,814

(a) Cash and cash equivalents includes $8 million that was initially classified as restricted cash as of the Effective Date but subsequently released from escrow and returned to the Successor. Restricted cash exclusive of the $8 million is not included in the table above.

Valuation Process

The fair values of our natural gas and oil properties, other property and equipment, other long-term assets, long-term debt, asset retirement obligations and warrants were estimated as of the Effective Date.

Natural gas and oil properties. The Company's principal assets are its natural gas and oil properties, which are accounted for under the successful efforts accounting method. The Company determined the fair value of its natural gas and oil properties based on the discounted future net cash flows expected to be generated from these assets. Discounted cash flow models by operating area were prepared using the estimated future revenues and operating costs for all proved developed properties and undeveloped properties comprising the proved and unproved reserves. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices escalated by an inflationary rate after five years, adjusted for differentials, and (v) a market-based weighted average cost of capital by operating area. The Company utilized NYMEX strip pricing, adjusted for differentials, to value the reserves. The NYMEX strip pricing inputs used are classified as Level 1 fair value assumptions and all other inputs are classified as Level 3 fair value assumptions. The discount rates utilized were derived using a weighted average cost of capital computation, which included an estimated cost of debt and equity for market participants with similar geographies and asset development type by operating area.

Other property and equipment. The fair value of other property and equipment such as buildings, land, computer equipment, and other equipment was determined using the replacement cost method under the cost approach which considers historical acquisition costs for the assets adjusted for inflation, as well as factors in any potential obsolescence based on the current condition of the assets and the ability of those assets to generate cash flow.

Long-term debt. A market approach, based upon quotes from major financial institutions, was used to measure the fair value of the $500 million aggregate principal amount of 5.50% Senior Notes due 2026 (the “2026 Notes”) and $500 million aggregate principal amount of 5.875% Senior Notes due 2029 (the “2029 Notes” and, together with the 2026 Notes, the “Notes”). The carrying value of borrowings under our Exit Credit Facility approximated fair value as the terms and interest rates were based on prevailing market rates.

Asset retirement obligations. The fair value of the Company’s asset retirement obligations was revalued based upon estimated reclamation costs for our assets with reclamation obligations, an appropriate long-term inflation adjustment, and our revised credit adjusted risk-free rate. The credit adjusted risk-free rate was based on an evaluation of an interest rate that equates to a risk-free interest rate adjusted for the effect of our credit standing.

Warrants. The fair values of the Warrants issued upon the Effective Date were estimated using a Black-Scholes model, a commonly used option-pricing model. The Black-Scholes model was used to estimate the fair value of the warrants with an implied stock price of $20.52; initial exercise price per share of $27.63, $32.13 and $36.18 for Class A, Class B and Class C Warrants, respectively; expected volatility of 58% estimated using volatilities of similar entities; risk-free rate using a 5-year Treasury bond rate; and an expected annual dividend yield which was estimated to be zero.

Condensed Consolidated Balance Sheet

The following consolidated balance sheet is as of February 9, 2021. This consolidated balance sheet includes adjustments that reflect the consummation of the transactions contemplated by the Plan (reflected in the column “Reorganization Adjustments”) as well as fair value adjustments as a result of the adoption of fresh start accounting (reflected in the column “Fresh Start Adjustments”) as of the Effective Date. The explanatory notes following the table below provide further details on the adjustments, including the assumptions and methods used to determine fair value for its assets, liabilities and warrants.

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Assets						
Current assets:						
Cash and cash equivalents	$ 243	$ (203)	(a)	$ —		$ 40
Restricted cash	—	86	(b)	—		86
Accounts receivable, net	861	(18)	(c)	—		843
Short-term derivative assets	—	—		—		—
Other current assets	66	(5)	(d)	—		61
Total current assets	1,170	(140)		—		1,030
Property and equipment:						
Natural gas and oil properties, successful efforts method						
Proved natural gas and oil properties	25,794	—		(21,108)	(o)	4,686
Unproved properties	1,546	—		(1,063)	(o)	483
Other property and equipment	1,755	—		(1,256)	(o)	499
Total property and equipment	29,095	—		(23,427)	(o)	5,668
Less: accumulated depreciation, depletion and amortization	(23,877)	—		23,877	(o)	—
Property and equipment held for sale, net	9	—		(7)	(o)	2
Total property and equipment, net	5,227	—		443	(o)	5,670
Other long-term assets	198	—		(84)	(p)	114
Total assets	$ 6,595	$ (140)		$ 359		$ 6,814

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Liabilities and stockholders' equity (deficit)						
Current liabilities:						
Accounts payable	$ 391	$ 24	(e)	$ —		$ 415
Current maturities of long-term debt, net	1,929	(1,929)	(f)	—		—
Accrued interest	4	(4)	(g)	—		—
Short-term derivative liabilities	398	—		—		398
Other current liabilities	645	124	(h)	—		769
Total current liabilities	3,367	(1,785)		—		1,582
Long-term debt, net	—	1,261	(i)	52	(q)	1,313
Long-term derivative liabilities	90	—		—		90
Asset retirement obligations, net of current portion	139	—		97	(r)	236
Other long-term liabilities	5	2	(j)	—		7
Liabilities subject to compromise	9,574	(9,574)	(k)	—		—
Total liabilities	13,175	(10,096)		149		3,228
Contingencies and commitments (Note 7)						
Stockholders' equity (deficit):						
Predecessor preferred stock	1,631	(1,631)	(l)	—		—
Predecessor common stock	—	—		—		—
Predecessor additional paid-in capital	16,940	(16,940)	(l)	—		—
Successor common stock	—	1	(m)	—		1
Successor additional paid-in-capital	—	3,585	(m)	—		3,585
Accumulated other comprehensive income	48	—		(48)	(s)	—
Accumulated deficit	(25,199)	24,941	(n)	258	(t)	—
Total stockholders' equity (deficit)	(6,580)	9,956		210		3,586
Total liabilities and stockholders' equity (deficit)	$ 6,595	$ (140)		$ 359		$ 6,814

Reorganization Adjustments

(a) The table below reflects the sources and uses of cash on the Effective Date from implementation of the Plan:

Sources:		
Proceeds from issuance of the Notes	$	1,000
Proceeds from Rights Offering		600
Proceeds from refunds of interest deposit for the Notes		5
Total sources of cash	$	1,605
Uses:		
Payment of roll-up of DIP Facility balance	$	(1,179)
Payment of Exit Credit Facility - Tranche A Loan		(479)
Transfers to restricted cash for professional fee reserve		(76)
Transfers to restricted cash for convenience claim distribution reserve		(10)
Payment of professional fees		(31)
Payment of DIP Facility interest and fees		(12)
Payment of FLLO alternative transaction fee		(12)
Payment of the Notes fees funded out of escrow		(8)
Payment of RBL interest and fees		(1)
Total uses of cash	$	(1,808)
Net cash used	$	(203)

(b) Represents the transfer of funds to a restricted cash account for purposes of funding the professional fee reserve and the convenience claim distribution reserve.

(c) Reflects the removal of an insurance receivable associated with a discharged legal liability.

(d) Reflects the collection of an interest deposit for the senior unsecured notes.

(e) Changes in accounts payable include the following:

Accrual of professional service provider success fees	$	38
Accrual of convenience claim distribution reserve		10
Accrual of professional service provider fees		5
Reinstatement of accounts payable from liabilities subject to compromise		2
Payment of professional fees		(31)
Net impact to accounts payable	$	24

(f) Reflects payment of the pre-petition credit facility for $1.179 billion and transfer of the Tranche A and Tranche B Loans to long-term debt for $750 million.

(g) Reflects payments of accrued interest and fees on the DIP Facility.

(h) Changes in other current liabilities include the following:

Reinstatement of other current liabilities from liabilities subject to compromise	$	191
Accrual of the Notes fees		2
Settlement of Put Option Premium through issuance of Successor Common Stock		(60)
Payment of DIP Facility fees		(9)
Net impact to other current liabilities	$	124

(i) Changes in long-term debt include the following:

Issuance of the Notes	$	1,000
Issuance of Tranche A and Tranche B Loans		750
Payments on Tranche A Loans		(479)
Debt issuance costs for the Notes		(10)
Net impact to long-term debt, net	$	1,261

(j) Reflects reinstatement of a long-term lease liability.

(k) On the Effective Date, liabilities subject to compromise were settled in accordance with the Plan as follows:

Liabilities subject to compromise pre-emergence	$	9,574
To be reinstated on the Effective Date:		
Accounts payable	$	(2)
Other current liabilities		(191)
Other long-term liabilities		(2)
Total liabilities reinstated	$	(195)
Consideration provided to settle amounts per the Plan or Reorganization:		
Issuance of Successor common stock associated with the Rights Offering and Backstop Commitment and settlement of the Put Option Premium	$	(2,311)
Proceeds from issuance of Successor common stock associated with the Rights Offering and Backstop Commitment		600
Issuance of Successor common stock to FLLO Term Loan holders, incremental to the Rights Offering and Backstop Commitment		(783)
Issuance of Successor common stock to Second Lien Note holders, incremental to the Rights Offering and Backstop Commitment		(124)
Issuance of Successor common stock to unsecured note holders		(45)
Issuance of Successor common stock to General Unsecured Claims		(8)
Fair value of Class A Warrants		(93)
Fair value of Class B Warrants		(94)
Fair value of Class C Warrants		(68)
Proceeds to holders of general unsecured claims		(10)
Total consideration provided to settle amounts per the Plan	$	(2,936)
Gain on settlement of liabilities subject to compromise	$	6,443

(l) Pursuant to the Plan, as of the Effective Date, all equity interests in Predecessor, including Predecessor's common and preferred stock, were canceled without any distribution.

(m) Reflects the Successor equity including the issuance of 97,907,081 shares of New Common Stock, 11,111,111 shares of Class A Warrants, 12,345,679 shares of Class B Warrants and 9,768,527 shares of Class C Warrants pursuant to the Plan.

Issuance of Successor equity associated with the Rights Offering and Backstop Commitment	$	2,371
Issuance of Successor equity to holders of the FLLO Term Loan, incremental to the Rights Offering and Backstop Commitment		783
Issuance of Successor equity to holders of the Second Lien Notes, incremental to the Rights Offering and Backstop Commitment		124
Issuance of Successor equity to holders of the unsecured senior notes		45
Issuance of Successor equity to holders of allowed general unsecured claims		8
Fair value of Class A warrants		93
Fair value of Class B warrants		94
Fair value of Class C warrants		68
Total change in Successor common stock and additional paid-in capital		3,586
Less: par value of Successor common stock		(1)
Change in Successor additional paid-in capital	$	3,585

(n) Reflects the cumulative net impact of the effects on accumulated deficit as follows:

Gain on settlement of liabilities subject to compromise	$	6,443
Accrual of professional service provider success fees		(38)
Accrual of professional service provider fees		(5)
Surrender of other receivable		(18)
Payment of FLLO alternative transaction fee		(12)
Total reorganization items, net		6,370
Cancellation of predecessor equity		18,571
Net impact on accumulated deficit	$	24,941

Fresh Start Adjustments

(o) Reflects fair value adjustments to our (i) proved natural gas and oil properties, (ii) unproved properties, (iii) other property and equipment and, (iv) property and equipment held for sale, and the elimination of accumulated depletion, depreciation and amortization.

(p) Reflects the fair value adjustment to record historical contracts at their fair values.

(q) Reflects the fair value adjustments to the 2026 Notes and 2029 Notes for $22 million and $30 million, respectively.

(r) Reflects the adjustment to our asset retirement obligations using assumptions as of the Effective Date, including an inflation factor of 2% and an average credit-adjusted risk-free rate of 5.18%.

(s) Reflects the fair value adjustment to eliminate the accumulated other comprehensive income of $9 million related to hedging settlements offset by the elimination of $57 million of income tax effects which has resulted in the recording of an income tax benefit of $57 million. See Note 11 for a discussion of income taxes.

(t) Reflects the net cumulative impact of the fresh start adjustments on accumulated deficit as follows:

Fresh start adjustments to property and equipment	$ 443
Fresh start adjustments to other long-term assets	(84)
Fresh start adjustments to long-term debt	(52)
Fresh start adjustments to long-term asset retirement obligations	(97)
Fresh start adjustments to accumulated other comprehensive income	(9)
Total fresh start adjustments impacting reorganizations items, net	201
Income tax effects on accumulated other comprehensive income	57
Net impact to accumulated deficit	$ 258

Reorganization Items, Net

We incurred significant expenses, gains and losses associated with the reorganization, primarily the gain on settlement of liabilities subject to compromise, write-off of unamortized debt issuance costs and related unamortized premiums and discounts, debt and equity financing fees, provision for allowed claims and legal and professional fees incurred subsequent to the Chapter 11 filings for the restructuring process. The accrual for allowed claims primarily represents damages from contract rejections and settlements attributable to the midstream savings requirement as stipulated in the Plan. While the claims reconciliation process is ongoing, we do not believe any existing unresolved claims will result in a material adjustment to the financial statements. The amount of these items, which were incurred in reorganization items, net within our accompanying consolidated statements of operations, have significantly affected our statements of operations.

We did not have any reorganization items, net for the 2023 Successor Period, 2022 Successor Period or the 2021 Successor Period. The following table summarizes the components in reorganization items, net included in our consolidated statements of operations:

	Predecessor
	Period from January 1, 2021 through February 9, 2021
Gains on the settlement of liabilities subject to compromise	$ 6,443
Accrual for allowed claims	(1,002)
Gain on fresh start adjustments	201
Gain from release of commitment liabilities	55
Professional service provider fees and other	(60)
Success fees for professional service providers	(38)
Surrender of other receivable	(18)
FLLO alternative transaction fee	(12)
Total reorganization items, net	$ 5,569

4. Natural Gas and Oil Property Transactions

Marcellus Acquisition

On March 9, 2022, we completed the acquisition of Chief and associated non-operated interests held by affiliates of Tug Hill, of premium drilling locations in the Marcellus Shale in Northeast Pennsylvania ("Marcellus Acquisition") for total consideration of approximately $2.77 billion, consisting of approximately $2 billion in cash, including working capital adjustments and approximately 9.4 million shares of our common stock, to acquire high quality producing assets and a deep inventory of premium drilling locations in the prolific Marcellus Shale in Northeast Pennsylvania. The Marcellus Acquisition was indebtedness free, effective as of January 1, 2022 and was subject to customary purchase price adjustments. We funded the cash portion of the consideration with cash on hand and $914 million of borrowings under the Company's Exit Credit Facility. See Note 6 for further discussion of debt. In the 2022 Successor Period, we recognized approximately $41 million of costs related to our Marcellus Acquisition, which included integration costs, consulting fees, financial advisory fees, legal fees and change in control expense in accordance with Chief's existing employment agreements. These acquisition-related costs are included within other operating expense (income), net within our consolidated statements of operations.

Marcellus Acquisition Purchase Price Allocation

We have accounted for the Marcellus Acquisition as a business combination, using the acquisition method. The following table represents the allocation of the total purchase price to the identifiable assets acquired and the liabilities assumed based on the fair values as of the acquisition date. We finalized the acquisition accounting for this transaction during the 2022 Successor Period, which resulted in measurement period adjustments of $39 million to both restricted cash and current liabilities, to reflect funds restricted for future payment of certain royalties.

	Purchase Price Allocation
Consideration:	
Cash	$ 2,000
Fair value of Chesapeake's common stock issued in the merger [a]	764
Working capital adjustments	6
Total consideration	$ 2,770
Fair Value of Liabilities Assumed:	
Current liabilities	$ 459
Other long-term liabilities	129
Amounts attributable to liabilities assumed	$ 588
Fair Value of Assets Acquired:	
Cash, cash equivalents and restricted cash	$ 39
Other current assets	218
Proved natural gas and oil properties	2,309
Unproved properties	788
Other property and equipment	1
Other long-term assets	3
Amounts attributable to assets acquired	$ 3,358
Total identifiable net assets	$ 2,770

(a) The fair value of our common stock is a Level 1 input, as our stock price is a quoted price in an active market as of the acquisition date.

Natural Gas and Oil Properties

For the Marcellus Acquisition, we applied applicable guidance, under which an acquirer should recognize the identifiable assets acquired and the liabilities assumed on the acquisition date at fair value. The fair value estimate of proved and unproved natural gas and oil properties as of the acquisition date was based on estimated natural gas and oil reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates of future production rates and future development costs. We utilized NYMEX strip pricing adjusted for inflation to value the reserves. We then applied various discount rates depending on the classification of reserves and other risk characteristics. Management utilized the assistance of a third-party valuation expert to estimate the value of the natural gas and oil properties acquired. Additionally, the fair value estimate of proved and unproved natural gas and oil properties was corroborated by utilizing a market approach, which considers recent comparable transactions for similar assets.

The inputs used to value natural gas and oil properties require significant judgment and estimates made by management and represent Level 3 inputs.

Marcellus Acquisition Revenues and Expenses Subsequent to Acquisition

We included in our consolidated statements of operations natural gas, oil and NGL revenues of $1,331 million, marketing revenues of $20 million, net losses on natural gas and oil derivatives of $379 million, and direct operating expenses of $483 million, including depreciation, depletion and amortization, related to the Marcellus Acquisition businesses for the period from March 10, 2022 (the date immediately following the completion of the Marcellus Acquisition) through December 31, 2022.

Vine Acquisition

On November 1, 2021, we acquired Vine, an energy company focused on the development of natural gas properties in the over-pressured stacked Haynesville and Mid-Bossier shale plays in Northwest Louisiana pursuant to a definitive agreement with Vine dated August 10, 2021, for total consideration of approximately $1.5 billion, consisting of approximately 18.7 million shares of our common stock and $90 million in cash. In conjunction with the Vine Acquisition, Vine's Second Lien Term Loan was repaid and terminated for $163 million inclusive of a $13 million make whole premium with cash on hand due to the agreement containing a change in control provision making the term loan callable upon closing. Vine's reserve-based loan facility, which had no borrowings as of November 1, 2021, was terminated at the time of the acquisition. Additionally, Vine's 6.75% Senior Notes, with a principal amount of $950 million were assumed by the Company. See Note 6 for additional discussion of the assumed debt. We funded the cash portion of the consideration with cash on hand. In the 2021 Successor Period, we recognized approximately $59 million of costs related to our acquisition of Vine, which included consulting fees, financial advisory fees, and legal fees. Additionally, we recognized approximately $36 million of severance expense as a result of the Vine Acquisition, which included $15 million of cash severance and $21 million of non-cash severance, primarily related to the issuance of New Common Stock for the acceleration of certain Vine restricted stock unit awards. A majority of Vine executives and employees were terminated on the date of the acquisition. These executives and employees were entitled to severance benefits in accordance with existing employment agreements. These acquisition-related costs are included within other operating expense (income), net within our consolidated statements of operations.

Vine Purchase Price Allocation

We have accounted for the Vine Acquisition as a business combination, using the acquisition method. The following table represents the allocation of the total purchase price of Vine to the identifiable assets acquired and the liabilities assumed based on the fair values as of the acquisition date. We finalized the acquisition accounting for this transaction during the 2022 Successor Period, which resulted in measurement period adjustments of $19 million to both deferred tax liabilities and unproved properties. See Note 11 for additional information regarding the change to deferred tax liabilities.

		Purchase Price Allocation
Consideration:		
Cash	$	253
Fair value of Chesapeake's common stock issued in the merger [(a)]		1,231
Restricted stock unit replacement awards		6
Total consideration	$	1,490
Fair Value of Liabilities Assumed:		
Current liabilities	$	765
Long-term debt		1,021
Deferred tax liabilities		30
Other long-term liabilities		272
Amounts attributable to liabilities assumed	$	2,088
Fair Value of Assets Acquired:		
Cash and cash equivalents	$	59
Other current assets		206
Proved natural gas and oil properties		2,181
Unproved properties		1,099
Other property and equipment		1
Other long-term assets		32
Amounts attributable to assets acquired	$	3,578
Total identifiable net assets	$	1,490

(a) The fair value of our common stock is a Level 1 input, as our stock price is a quoted price in an active market as of the acquisition date.

Natural Gas and Oil Properties

For the Vine Acquisition, we applied applicable guidance, under which an acquirer should recognize the identifiable assets acquired and the liabilities assumed on the acquisition date at fair value. The fair value estimate of proved and unproved natural gas and oil properties as of the acquisition date was based on estimated natural gas and oil reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates of future production rates and future development costs. We utilized NYMEX strip pricing adjusted for inflation to value the reserves. We then applied various discount rates depending on the classification of reserves and other risk characteristics. Management utilized the assistance of a third-party valuation expert to estimate the value of the natural gas and oil properties acquired. Additionally, the fair value estimate of proved and unproved natural gas and oil properties was corroborated by utilizing a market approach, which considers recent comparable transactions for similar assets.

The inputs used to value natural gas and oil properties require significant judgment and estimates made by management and represent Level 3 inputs.

Financial Instruments and Other

The fair value measurements of long-term debt were estimated based on a market approach using estimates provided by an independent investment data services firm and represent Level 2 inputs.

Restricted Stock Unit Replacement Awards

Included in consideration for the Vine Acquisition is approximately $6 million related to pre-combination service recognized on Vine's restricted stock unit awards. For restricted stock units that were accelerated or transitioned at the time of the merger, we recognized expense for the portion of the award that was accelerated and included in consideration the portion of the award related to pre-combination service.

Vine Revenues and Expenses Subsequent to Acquisition

We included in our consolidated statements of operations natural gas, oil and NGL revenues of $290 million, net gains on natural gas and oil derivatives of $144 million, direct operating expenses of $177 million, including depreciation, depletion and amortization, and other expense of $12 million related to the Vine business for the period from November 1, 2021 to December 31, 2021. We included in our consolidated statements of operations natural gas, oil and NGL revenues of $1,863 million, net losses on natural gas and oil derivatives of $624 million, direct operating expenses of $924 million, including depreciation, depletion and amortization, and other expense of $39 million related to the Vine business for the 2022 Successor Period.

Combined Pro Forma Financial Information

As the Marcellus Acquisition closed on March 9, 2022, all subsequent activity is included in Chesapeake's consolidated statements of operations for the 2023 Successor Period. As the Vine Acquisition closed on November 1, 2021, all subsequent activity is included in Chesapeake's consolidated statements of operations for the 2022 Successor Period and 2023 Successor Period. The following unaudited pro forma financial information is based on our historical consolidated financial statements adjusted to reflect as if the Marcellus Acquisition and Vine Acquisition had each occurred on February 10, 2021, the date Chesapeake emerged from bankruptcy. See Note 2 for additional information on the bankruptcy. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including the estimated tax impact of the pro forma adjustments.

	Successor	
	Year Ended December 31, 2022	**Period from February 10, 2021 through December 31, 2021**
Revenues	$ 11,743	$ 5,891
Net income (loss) available to common stockholders	$ 4,765	$ (5)
Earnings (loss) per common share:		
Basic	$ 37.37	$ (0.04)
Diluted	$ 32.26	$ (0.04)

Eagle Ford Divestitures

In January 2023, we entered into an agreement to sell a portion of our Eagle Ford assets to WildFire Energy I LLC for approximately $1.425 billion, subject to customary post-closing adjustments. Approximately $225 million of the purchase price was recorded as deferred consideration and treated as a non-interest-bearing note to be paid in installments of $60 million per year for the next three years, with $45 million to be paid in the fourth year following the transaction close date. The deferred consideration is recorded at fair value with an imputed rate of interest as a Level 2 input, and approximately $58 million of the deferred consideration is reflected within other current assets and approximately $135 million is reflected within other long-term assets on the consolidated balance sheets as of December 31, 2023. The divestiture, which closed on March 20, 2023 (with an effective date of October 1, 2022), resulted in a gain of approximately $337 million, inclusive of post-closing adjustments, based on the difference between the carrying value of the assets and consideration received. As of December 31, 2022, approximately $811 million of property and equipment, net, and $8 million of other assets were classified as assets held for sale on the consolidated balance sheets. Additionally, approximately $65 million of derivative liabilities, $57 million of asset retirement obligations and $22 million of other liabilities were classified as held for sale and included within other current liabilities on the consolidated balance sheets as of December 31, 2022.

In February 2023, we entered into an agreement to sell a portion of our remaining Eagle Ford assets to INEOS Upstream Holdings Limited ("INEOS Energy") for approximately $1.4 billion, subject to customary post-closing adjustments. Approximately $225 million of the purchase price was recorded as deferred consideration and treated as a non-interest-bearing note to be paid in installments of approximately $56 million per year for the next four years. The deferred consideration is recorded at fair value with an imputed rate of interest as a Level 2 input, and approximately $55 million of the deferred consideration is reflected within other current assets and approximately $144 million is reflected within other long-term assets on the consolidated balance sheets as of December 31, 2023. The divestiture, which closed on April 28, 2023 (with an effective date of October 1, 2022), resulted in a gain of approximately $470 million, based on the difference between the carrying value of the assets and consideration received. Included within the liabilities assumed by INEOS Energy was approximately $53 million of asset retirement obligations.

In August 2023, we entered into an agreement to sell the final portion of our remaining Eagle Ford assets to SilverBow Resources, Inc. ("SilverBow") for approximately $700 million, subject to customary post-closing adjustments. Approximately $50 million of the purchase price was recorded as deferred consideration and treated as a non-interest-bearing note to be paid one year from the closing date. The deferred consideration is recorded at fair value with an imputed rate of interest as a Level 2 input, and approximately $46 million of the deferred consideration is reflected within other current assets on the consolidated balance sheets as of December 31, 2023. Additionally, SilverBow has agreed to pay Chesapeake an additional contingent payment of $25 million should WTI NYMEX prices average between $75 and $80 per barrel or $50 million should WTI NYMEX prices average above $80 per barrel during the year following the close of the transaction. The fair value of the contingent consideration as of December 31, 2023 of $12 million is reflected within short-term derivative assets within our consolidated balance sheets. See Note 15 for additional information. The divestiture, which closed on November 30, 2023 (with an effective date of February 1, 2023), resulted in a gain of approximately $140 million, based on the difference between the carrying value of the assets and consideration received. Included within the liabilities assumed by SilverBow was approximately $11 million of asset retirement obligations.

Powder River Divestiture

In January 2022, Chesapeake signed an agreement to sell its Powder River Basin assets in Wyoming to Continental Resources, Inc. for approximately $450 million, subject to customary post-closing adjustments. The divestiture, which closed on March 25, 2022, resulted in the recognition of a gain of approximately $293 million, which included $13 million of post-close adjustments, based on the difference between the carrying value of the assets and the cash received.

5. Earnings Per Share

Basic earnings per common share is computed by dividing the net income available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted earnings per common share is calculated in the same manner but includes the impact of potentially dilutive securities utilizing the treasury stock method. Potentially dilutive securities during the Successor Periods consist of issuable shares related to warrants, unvested restricted stock units, and unvested performance share units and during the Predecessor Period consisted of unvested restricted stock units, contingently issuable shares related to preferred stock and convertible senior notes unless their effect was antidilutive.

The reconciliations between basic and diluted earnings per share are as follows:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Numerator				
Net income available to common stockholders, basic and diluted	$ 2,419	$ 4,869	$ 945	$ 5,383
Denominator (in thousands)				
Weighted average common shares outstanding, basic	132,840	125,785	101,754	9,781
Effect of potentially dilutive securities				
Preferred stock	—	—	—	290
Warrants	9,750	19,734	14,376	—
Restricted stock units	338	395	200	—
Performance share units	48	47	11	—
Weighted average common shares outstanding, diluted	142,976	145,961	116,341	10,071
Earnings per common share:				
Basic	$ 18.21	$ 38.71	$ 9.29	$ 550.35
Diluted	$ 16.92	$ 33.36	$ 8.12	$ 534.51

Successor

During the 2023, 2022 and 2021 Successor Periods, the diluted earnings per share calculation excludes the effect of 777,369, 789,458 and 1,228,828 reserved shares of common stock and 1,466,502, 1,489,337 and 2,318,446 reserved Class C Warrants related to the settlement of General Unsecured Claims associated with the Chapter 11 Cases, as all necessary conditions had not been met for such shares to be considered dilutive shares during the 2023, 2022 and 2021 Successor Periods, respectively.

Predecessor

We had the option to settle conversions of the 5.50% convertible senior notes due 2026 with cash, shares or common stock or any combination thereof. As the price of our common stock was below the conversion threshold level for any time during the conversion period, there was no impact to diluted earnings per share.

6. Debt

Our long-term debt consisted of the following as of December 31, 2023 and 2022:

	Successor			
	December 31, 2023		December 31, 2022	
	Carrying Amount	Fair Value[a]	Carrying Amount	Fair Value[a]
New Credit Facility	$ —	$ —	$ 1,050	$ 1,050
5.50% senior notes due 2026	500	496	500	485
5.875% senior notes due 2029	500	489	500	475
6.75% senior notes due 2029[b]	950	958	950	917
Premiums on senior notes	83	—	100	—
Debt issuance costs	(5)	—	(7)	—
Total long-term debt, net	$ 2,028	$ 1,943	$ 3,093	$ 2,927

(a) The carrying value of borrowings under our New Credit Facility approximates fair value as the interest rates are based on prevailing market rates; therefore, they are a Level 1 fair value measurement. For all other debt, a market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value.

(b) On November 1, 2021, we acquired the debt of Vine, which consisted of 6.75% senior notes due 2029. See further discussion below.

The table below presents debt maturities as of December 31, 2023, excluding debt issuance costs and premiums:

	Total
2024	$ —
2025	—
2026	500
2027	—
2028	—
Thereafter	1,450
Total long-term debt	$ 1,950

New Credit Facility. In December 2022, we entered into a senior secured reserve-based credit agreement (the “New Credit Agreement”) with the lenders and issuing banks party thereto (the “Lenders”), and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (in such capacity, the “Administrative Agent”), providing for a reserve-based credit facility (the “New Credit Facility”) with an initial borrowing base of $3.5 billion and aggregate commitments of $2.0 billion. The New Credit Facility matures in December 2027. The New Credit Facility provides for a $200 million sublimit available for the issuance of letters of credit and a $50 million sublimit available for swingline loans. As of December 31, 2023, we have approximately $2.0 billion available for borrowings under the New Credit Facility.

Initially, the obligations under the New Credit Facility are guaranteed by certain of Chesapeake’s subsidiaries (the “Guarantors”), and the New Credit Facility is secured by substantially all of the assets owned by the Company and the Guarantors (subject to customary exceptions), including mortgages on not less than 85% of the total PV-9 of the borrowing base properties evaluated in the most recent reserve report (where PV-9 is the net present value, discounted at 9% per annum, of the estimated future net revenues). The borrowing base will be redetermined semi-annually in or around April and October of each year, with one interim “wildcard” redetermination available to each of the Company and the Administrative Agent, the latter at the direction of the Required Lenders (as defined in the New Credit Agreement), between scheduled redeterminations. Our borrowing base was reaffirmed in October 2023, and the next scheduled redetermination will be in or around April 2024. The New Credit Agreement contains restrictive covenants that limit Chesapeake and its subsidiaries' ability to, among other things but subject to exceptions customary to reserve-based credit facilities: (i) incur additional indebtedness, (ii) make investments, (iii) enter into mergers; (iv) make or declare dividends; (v) repurchase or redeem certain indebtedness; (vi) enter into certain hedges; (vii) incur liens; (viii) sell assets; and (ix) engage in certain transactions with affiliates. The New Credit Agreement requires Chesapeake to maintain compliance with the following financial ratios: (A) a current ratio, which is the ratio of Chesapeake's and its restricted subsidiaries' consolidated current assets (including unused commitments under the New Credit Facility but excluding certain non-cash assets) to their consolidated current liabilities (excluding the current portion of long-term debt and certain non-cash liabilities), of not less than 1.00 to 1.00; (B) a net leverage ratio, which is the ratio of total indebtedness (less unrestricted cash up to a specified threshold) to Consolidated EBITDAX (as defined in the Credit Agreement) for the prior four fiscal quarters, of not greater than 3.50 to 1.00 and (C) a PV-9 coverage ratio of the net present value, discounted at 9% per annum, of the estimated future net revenues expected in the proved reserves to Chesapeake's and its restricted subsidiaries' total indebtedness of not less than 1.50 to 1.00.

Borrowings under the New Credit Agreement may be alternate base rate loans or term SOFR loans, at our election. Interest is payable quarterly for alternate base rate loans and at the end of the applicable interest period for term SOFR loans. Term SOFR loans bear interest at term SOFR plus an applicable rate ranging from 175 to 275 basis points per annum, depending on the percentage of the commitments utilized, plus an additional 10 basis points per annum credit spread adjustment. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted term SOFR rate for a one-month interest period plus 100 basis points, plus an applicable margin ranging from 75 to 175 basis points per annum, depending on the percentage of the commitments utilized. Chesapeake also pays a commitment fee on unused commitment amounts under the Credit Facility ranging from 37.5 to 50 basis points per annum, depending on the percentage of the commitments utilized.

The New Credit Facility is subject to customary events of default, remedies, and cure rights for credit facilities of this nature.

Exit Credit Facility. On the Effective Date, pursuant to the terms of the Plan, the Company, as borrower, entered into a reserve-based credit agreement (the "Credit Agreement") providing for a reserve-based credit facility with an initial borrowing base of $2.5 billion. The aggregate initial elected commitments of the lenders under the Exit Credit Facility were $1.75 billion of Tranche A Loans and $221 million of fully funded Tranche B Loans.

The Exit Credit Facility provided for a $200 million sublimit of the aggregate commitments that was available for the issuance of letters of credit. The Exit Credit Facility bore interest at the ABR (alternate base rate) or LIBOR, at our election, plus an applicable margin (ranging from 2.25–3.25% per annum for ABR loans and 3.25–4.25% per annum for LIBOR loans, subject to a 1.00% LIBOR floor), depending on the percentage of the borrowing base then being utilized. The Tranche A Loans were due to mature three years after the Effective Date and the Tranche B Loans were due to mature four years after the Effective Date. The Company was required to pay a commitment fee of 0.50% per annum on the average daily unused portion of the current aggregate commitments under the Tranche A Loans.

The Credit Agreement was subject to various financial and other covenants and also contained customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws and anti-corruption laws), delivery of quarterly and annual financial statements, conduct of business, maintenance of property, maintenance of insurance, restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments, and other customary covenants. In December 2022, the Tranche A Loans and Tranche B Loans were both repaid and the Exit Credit Facility was terminated.

Borrowings under our credit agreements bore interest at an average interest rate of 8.7% during the 2022 Successor Period. The Company has no additional secured debt as of December 31, 2023.

Outstanding Senior Notes. On February 2, 2021, Chesapeake Escrow Issuer LLC, then an indirect wholly owned subsidiary of the Company, issued $500 million aggregate principal amount of its 2026 Notes and

$500 million aggregate principal amount of its 2029 Notes. The Notes included a $52 million premium to reflect fair value adjustments at the date of emergence.

The Notes are guaranteed on a senior unsecured basis by each of the Company's subsidiaries that guaranteed the Exit Credit Facility.

The Notes were issued pursuant to an indenture, dated as of February 5, 2021, among the Issuer, the guarantor party thereto and Deutsche Bank Trust Company Americas, as trustee.

Interest on the Notes is payable semi-annually, on February 1 and August 1 of each year to holders of record on the immediately preceding January 15 and July 15.

Vine Senior Notes

As a result of the completion of the Vine Acquisition, the Company and certain of its subsidiaries entered into a supplemental indenture pursuant to which the Company assumed the obligations under Vine's $950 million aggregate principal amount of 6.75% senior notes due 2029 (the "Vine Notes") issued under the indenture dated April 7, 2021 with Wilmington Trust, National Association, as Trustee (the "Vine Indenture"). The Vine Notes included a $71 million premium to reflect fair value adjustments at the date of acquisition.

The Company and certain of its subsidiaries have agreed to guarantee such obligations under the Vine Indenture. Additionally, certain subsidiaries of Vine entered into a supplemental indenture to the Company's existing indenture, dated February 5, 2021, with Deutsche Bank Trust Company Americas as trustee (the "CHK Indenture"), pursuant to which such subsidiaries of Vine have agreed to guarantee obligations under the CHK Indenture.

Interest on the Vine Notes is payable semi-annually, on April 15 and October 15 of each year to holders of record on the immediately preceding April 1 and October 1.

The Notes and the Vine Notes are the Company's senior unsecured obligations. Accordingly, they rank (i) equal in right of payment to all existing and future senior unsecured indebtedness, (ii) effectively subordinate in right of payment to all existing and future secured indebtedness, including indebtedness under the New Credit Facility, to the extent of the value of the collateral securing such indebtedness, (iii) structurally subordinate in right of payment to all existing and future indebtedness and other liabilities of any future subsidiaries that do not guarantee the Notes and any entity that is not a subsidiary that does not guarantee the Notes and (iv) senior in right of payment to all future subordinated indebtedness. Each guarantee of the Notes by a guarantor is a general, unsecured, senior obligation of such guarantor. Accordingly, the guarantees (i) rank equally in right of payment with all existing and future senior indebtedness of such guarantor (including such guarantor's guarantee of indebtedness under the New Credit Facility), (ii) are subordinated to all existing and future secured indebtedness of such guarantor, including such guarantor's guarantee of indebtedness under our New Credit Facility, to the extent of the value of the collateral of such guarantor securing such secured indebtedness, (iii) are structurally subordinated to all indebtedness and other liabilities of any future subsidiaries of such guarantor that do not guarantee the notes and (iv) rank senior in right of payment to all future subordinated indebtedness of such guarantor.

7. Contingencies and Commitments

Contingencies

Business Operations and Litigation and Regulatory Proceedings

We are involved in, and expect to continue to be involved in, various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Our total accrued liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates, and our final liabilities may ultimately be materially different.

The majority of the Company's pre-petition legal proceedings were settled during the Chapter 11 Cases or will be resolved in connection with the claims reconciliation process before the Bankruptcy Court, together with actions seeking to collect pre-petition indebtedness or to exercise control over the property of the Company's bankruptcy estates. Any allowed claim related to such litigation will be treated in accordance with the Plan. The Plan in the Chapter 11 Cases, which became effective on February 9, 2021, provided for the treatment of claims against the Company's bankruptcy estates, including pre-petition liabilities that had not been satisfied or addressed during the Chapter 11 Cases. Many of these proceedings were in early stages, and many of them sought damages and penalties, the amount of which is indeterminate. See Note 2 for additional information.

Environmental Contingencies

The nature of the natural gas and oil business carries with it certain environmental risks for us and our subsidiaries. We have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. We conduct periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, we may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

Other Matters

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Commitments

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas, oil and NGL to move certain of our production to market. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, they are reflected in our estimates of proved reserves.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, credits for third-party volumes or future costs under cost-of-service agreements, are presented below:

	Successor
	December 31, 2023
2024	$ 284
2025	255
2026	235
2027	208
2028	194
2029-2036	956
Total	$ 2,132

During the 2023 Successor Period, certain gathering, processing and transportation agreements were transferred to the buyers of our Eagle Ford assets. In addition, we have long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually, or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees may vary with the applicable agreement.

Other Commitments

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging for, financial or performance assurances to third parties on behalf of our wholly owned guarantor subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantee our subsidiaries' future performance.

In connection with acquisitions and divestitures, our purchase and sale agreements generally provide indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party and/or other specified matters. These indemnifications generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or cannot be quantified at the time of entering into or consummating a particular transaction. For divestitures of natural gas and oil properties, our purchase and sale agreements may require the return of a portion of the proceeds we receive as a result of uncured title or environmental defects.

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

8. Other Liabilities

Other current liabilities as of December 31, 2023 and 2022 are detailed below:

	Successor	
	December 31, 2023	December 31, 2022
Revenues and royalties due to others	$ 360	$ 734
Accrued drilling and production costs	211	253
Accrued hedging costs	2	109
Accrued compensation and benefits	64	72
Taxes payable	84	84
Operating leases	84	86
Joint interest prepayments received	8	34
Current liabilities held for sale[(a)]	—	144
Other	34	111
Total other current liabilities	$ 847	$ 1,627

(a) As of December 31, 2022, certain liabilities associated with the sale of a portion of our Eagle Ford assets were classified as current liabilities held for sale. See Note 4 for additional information.

9. Leases

We are a lessee under various agreements for drilling rigs, compressors, vehicles and gas treating plants. As of December 31, 2023, these leases have remaining terms ranging from one month to three years. Certain of our lease agreements include options to renew the lease, terminate the lease early or purchase the underlying asset at the end of the lease. We determine the lease term at the lease commencement date as the non-cancelable period of the lease, including options to extend or terminate the lease when we are reasonably certain to exercise the option. The company's vehicles are the only leases with renewal options that we are reasonably certain to exercise. The renewals are reflected in the right of use ("ROU") asset and lease liability balances.

Our operating ROU assets are included in other long-term assets while operating lease liabilities are included in other current and other long-term liabilities on the consolidated balance sheet.

The following table presents our ROU assets and lease liabilities as of December 31, 2023 and 2022. As of December 31, 2023 and 2022, we did not have any finance leases.

	Successor	
	Operating Leases	
	December 31, 2023	December 31, 2022
ROU assets	$ 99	$ 119
Lease liabilities:		
Current lease liabilities	$ 84	$ 86
Long-term lease liabilities	15	33
Total lease liabilities, net	$ 99	$ 119

Additional information for the Company's operating and finance leases is presented below:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Lease cost:				
Finance lease cost	$ —	$ —	$ —	$ 1
Operating lease cost	107	51	33	3
Short-term lease cost	40	74	13	—
Total lease cost	$ 147	$ 125	$ 46	$ 4
Other information:				
Operating cash outflows from operating leases	$ 10	$ 15	$ 7	$ —
Investing cash outflows from operating leases	$ 137	$ 110	$ 39	$ 3
Financing cash outflows from finance lease	$ —	$ —	$ —	$ 1

	Successor	
	December 31, 2023	December 31, 2022
Weighted average remaining lease term - operating leases	1.24 years	1.54 years
Weighted average discount rate - operating leases	7.02 %	6.64 %

Maturity analysis of operating lease liabilities is presented below:

	Successor
	December 31, 2023
2024	$ 85
2025	17
2026	1
Total lease payments	103
Less imputed interest	(4)
Present value of lease liabilities	99
Less current maturities	(84)
Present value of lease liabilities, less current maturities	$ 15

10. Revenue

The following tables show revenue disaggregated by operating area and product type, for the periods presented:

	Successor			
	Year Ended December 31, 2023			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 1,483	$ —	$ —	$ 1,483
Haynesville	1,300	—	—	1,300
Eagle Ford	70	596	98	764
Natural gas, oil and NGL revenue	$ 2,853	$ 596	$ 98	$ 3,547
Marketing revenue	$ 989	$ 1,332	$ 179	$ 2,500

	Successor			
	Year Ended December 31, 2022			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 4,041	$ —	$ —	$ 4,041
Haynesville	3,481	—	—	3,481
Eagle Ford	261	1,798	212	2,271
Powder River Basin	20	66	13	99
Natural gas, oil and NGL revenue	$ 7,803	$ 1,864	$ 225	$ 9,892
Marketing revenue	$ 2,455	$ 1,547	$ 229	$ 4,231

	Successor			
	Period from February 10, 2021 through December 31, 2021			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 1,370	$ —	$ —	$ 1,370
Haynesville	998	—	—	998
Eagle Ford	179	1,354	179	1,712
Powder River Basin	75	202	44	321
Natural gas, oil and NGL revenue	$ 2,622	$ 1,556	$ 223	$ 4,401
Marketing revenue	$ 908	$ 1,158	$ 197	$ 2,263

	Predecessor			
	Period from January 1, 2021 through February 9, 2021			
	Natural Gas	Oil	NGL	Total
Marcellus	$ 119	$ —	$ —	$ 119
Haynesville	53	—	—	53
Eagle Ford	17	159	17	193
Powder River Basin	7	20	6	33
Natural gas, oil and NGL revenue	$ 196	$ 179	$ 23	$ 398
Marketing revenue	$ 78	$ 141	$ 20	$ 239

Major Customers

For the 2023 Successor Period, sales to Valero Energy Corporation and Shell Energy North America accounted for approximately 17% and 10%, respectively, of total revenues (before the effects of hedging). For the 2022 Successor Period, sales to Shell Energy North America and Valero Energy Corporation accounted for approximately 13% and 10%, respectively, of total revenues (before the effects of hedging). For the 2021 Successor Period, sales to Valero Energy Corporation and Energy Transfer Crude Marketing accounted for approximately 14% and 11%, respectively, of total revenues (before the effects of hedging). For the 2021 Predecessor Period, sales to Valero Energy Corporation accounted for approximately 19% of total revenues (before the effects of hedging). No other purchasers accounted for more than 10% of our total revenues during the 2023 Successor Period, 2022 Successor Period, 2021 Successor Period or 2021 Predecessor Period.

Accounts Receivable

Accounts receivable as of December 31, 2023 and 2022 are detailed below:

	Successor	
	December 31, 2023	December 31, 2022
Natural gas, oil and NGL sales	$ 406	$ 1,171
Joint interest	180	246
Other	8	24
Allowance for doubtful accounts	(1)	(3)
Total accounts receivable, net	$ 593	$ 1,438

11. Income Taxes

The components of the income tax expense (benefit) for each of the periods presented below are as follows:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Current				
Federal	$ 264	$ 37	$ —	$ —
State	6	10	—	—
Current Income Taxes	270	47	—	—
Deferred				
Federal	381	(1,112)	(45)	(54)
State	47	(220)	(4)	(3)
Deferred Income Taxes	428	(1,332)	(49)	(57)
Total	$ 698	$ (1,285)	$ (49)	$ (57)

The income tax expense (benefit) reported in our consolidated statement of operations is different from the federal income tax expense (benefit) computed using the federal statutory rate for the following reasons:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Income tax expense (benefit) at the federal statutory rate of 21%	$ 655	$ 767	$ 188	$ 1,119
State income taxes (net of federal income tax benefit)	56	75	(86)	238
Change in valuation allowance due to Acquisitions	—	19	(49)	—
Change in valuation allowance excluding impact of Acquisitions	(33)	(2,147)	(179)	(1,191)
Reorganization items	—	—	60	(173)
Transaction costs	—	2	11	—
Removal of stranded tax effects in accumulated other comprehensive income	—	—	—	(57)
Other	20	(1)	6	7
Total	$ 698	$ (1,285)	$ (49)	$ (57)

Our state income tax provision is affected by changes in our state apportionment, changes in state tax rates, as well as state specific tax adjustments. Shifts in our state apportionment factors may cause our deferred taxes to be remeasured. The 2021 Successor Period resulted in a state tax benefit as a result of the Vine acquisition causing an increase to our Louisiana deferred tax asset. We recognize certain permanent book-to-tax differences relating to reorganization items such as differences in the treatment of the extinguishment of liabilities and differences due to the non-deductibility of certain expenses associated with administering the plan of reorganization.

Deferred income taxes are provided to reflect temporary differences in the tax basis of assets and liabilities and their reported amounts in the financial statements. The tax-effected temporary differences, net operating loss ("NOL") carryforwards and excess business interest expense carryforwards that comprise our deferred income taxes are as follows:

	Successor	
	December 31, 2023	December 31, 2022
Deferred tax liabilities:		
Property, plant and equipment	$ (295)	$ (253)
Derivative instruments	(166)	—
Right of use lease asset	(25)	(30)
Other	(4)	(5)
Deferred tax liabilities	(490)	(288)
Deferred tax assets:		
Net operating loss carryforwards	848	870
Carrying value of debt	25	29
Excess business interest expense carryforward	646	665
Capital loss carryforwards	78	101
Asset retirement obligations	65	91
Investments	1	11
Future lease payments	25	30
Accrued liabilities	15	21
Derivative instruments	—	137
Other	32	29
Deferred tax assets	1,735	1,984
Valuation allowance	(312)	(345)
Deferred tax assets after valuation allowance	1,423	1,639
Net deferred tax asset	$ 933	$ 1,351

As of December 31, 2023 and 2022, we had deferred tax assets of $1.735 billion and $1.984 billion, respectively, upon which we had a valuation allowance of $312 million and $345 million, respectively. The net change in the valuation allowance of $33 million is primarily due to the expiration of a capital loss carryforward and is reflected as a component of income tax expense in the consolidated statements of operations.

A valuation allowance against deferred tax assets, including NOL carryforwards and disallowed business interest carryforwards, is recognized when it is more likely than not that all or some portion of the benefit from the deferred tax assets will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of existing taxable temporary differences, tax planning strategies, as well as the current and forecasted business economics of our industry. Management assesses all available evidence, both positive and negative, to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets.

For the year ended December 31, 2021, we maintained a full valuation allowance against our deferred tax assets based upon the conclusion that it was more likely than not that the deferred tax assets would not be realized. An item of negative evidence consisted of the cumulative pre-tax book losses over rolling three-year periods, primarily due to recurring operational losses and impairments of proved natural gas and oil properties recorded in 2020. For the cumulative three-year period ended December 31, 2022, we were in a cumulative loss position, but given the magnitude of the 2020 losses rolling off relative to the 2021 and 2022 positive pre-tax book income, we anticipated a return to cumulative pre-tax income during 2023. The expectation of future earnings along with reversals of existing taxable timing differences provided us with sufficient positive evidence to conclude that $1.351 billion of our federal and state deferred tax assets were more likely than not to be realized. Accordingly, we released the valuation allowance for this amount during 2022. We continue to maintain a partial valuation allowance of $312 million against a portion of our federal and state deferred tax assets such as NOLs, credit carryovers, and capital losses, which may expire before we are able to utilize them due to the application of the limitations under Section 382 and the ordering in which such attributes may be applied.

Our ability to utilize NOL carryforwards, disallowed business interest carryforwards, tax credits and possibly other tax attributes to reduce future taxable income and federal income tax is subject to various limitations under Section 382 of the Code. The utilization of such attributes may be subject to an annual limitation under Section 382 of the Code should transactions involving our equity result in a cumulative shift of more than 50% in the beneficial ownership of our stock during any three-year testing period (an “Ownership Change”).

As a result of emergence from bankruptcy on February 9, 2021, the Company did experience an Ownership Change. The amount of the annual limitation has been computed to be $54 million. The limitation applies to our NOL carryforwards, disallowed business interest carryforwards and general business credits until such attributes expire or are fully utilized. As we were in an overall net unrealized built-in loss position at the Effective Date, the limitation also applies to any recognized built-in losses incurred for a period of five years but only to the extent of the overall net unrealized built-in loss. Recognized built-in losses include a portion of our tax depreciation, depletion, and amortization deductions along with a portion of our realized hedging losses. We incurred sufficient recognized built-in losses during the 2021 tax year such that we have no further restriction on the company’s deduction for such items. Some states impose similar limitations on tax attribute utilization upon experiencing an Ownership Change.

In Chapter 11 bankruptcy cases, the cancellation of debt income (“CODI”) realized upon emergence from bankruptcy is excludible from taxable income but results in a reduction of tax attributes in accordance with the attribute reduction and ordering rules of Section 108 of the Code. The amount of our CODI was $5 billion, all of which reduced our NOL carryforwards. As a result of the Section 382 limitation, $307 million of federal NOLs remaining after the CODI reduction were estimated to expire before they would become utilizable and, as such, were removed from our deferred tax assets. The states we operate in generally have similar rules for attribute reduction and Section 382 limitation which resulted in the reduction of certain of our state NOL carryforwards.

On November 1, 2021, we completed the acquisition of Vine. For federal income tax purposes, the transaction qualified as a tax-free merger under Section 368 of the Code and, as a result, we acquired carryover tax basis in Vine’s assets and liabilities. In the 2021 Successor Period, we recorded a $49 million net deferred tax liability determined through business combination accounting. Upon the completion of Vine’s tax returns in the 2022 Successor Period, the net deferred tax liability was adjusted to $30 million. As a result of this adjustment to the deferred tax liability, we increased our valuation allowance and recorded $19 million of income tax expense in the 2022 Successor Period. Additionally, we acquired NOL and interest expense carryforwards which are subject to a base annual Section 382 limitation of approximately $2 million. The base annual limitation is estimated to be increased over the first five years for recognized built-in gains of approximately $12 million per year resulting in approximately $14 million per year of available utilization in those years.

The Marcellus Acquisition during the 2022 Successor Period was treated as a taxable asset acquisition with no tax carryovers acquired.

As of December 31, 2023, and after taking into account each of the foregoing matters, the federal NOLs and excess business interest attributes are as follows:

	Attributes subject to Section 382 base annual limitation		Attributes not subject to Section 382 limitation
	$54 million	$2 million	
Net operating losses, by year of expiration:			
2037	$ 760	$ 24	$ —
Indefinitely lived	2,268	102	—
Total federal net operating losses	$ 3,028	$ 126	$ —
Excess business interest expense (indefinitely lived)	$ 1,381	$ 75	$ 1,277

We had state NOL carryforwards of approximately $3.712 billion. Several states adopt the federal NOL carryforward period such that our more recent state NOLs do not expire. The state NOL carryforwards are subject to apportioned amounts of the federal Section 382 limitations.

Should we complete the Southwestern Merger as further discussed in Note 21, we anticipate triggering a Section 382 Ownership Change for purposes of both Southwestern's tax attributes as well as for our own. Assuming that generally higher long-term tax-exempt rates continue to apply as compared to prior years, we believe that the annual limitation will be less restrictive than the annual limitations that resulted from prior ownership changes. As a result, the new limitation would generally only apply to those attributes generated subsequent to the previous ownership changes.

As of December 31, 2023 and 2022, we have an income tax receivable of $33 million and $168 million included in other current assets within our consolidated balance sheets, respectively.

On August 16, 2022, the President of the United States signed into law the Inflation Reduction Act of 2022 ("IRA") which, among other things, includes provisions for a 15% corporate alternative minimum tax on book income for companies whose average book income exceeds $1 billion for any three consecutive years preceding the tax year and a 1% excise tax on stock buybacks. These changes are generally in effect for tax years beginning after December 31, 2022. Based on our book income in the past three years, we do not believe we are subject to the corporate alternative minimum tax in 2023. However, we may become subject to the corporate alternative minimum tax in future years. It is our policy that we view the alternative minimum tax as an excess tax over regular income tax and therefore, our deferred tax assets will continue to be assessed for realizability on the basis of whether they reduce a regular tax liability. Should we pay alternative minimum tax in the future and thus acquire credit carryovers related thereto, such deferred tax assets on these will be separately evaluated for valuation allowance purposes.

Accounting guidance for recognizing and measuring uncertain tax positions requires a more likely than not threshold condition be met on a tax position, based solely on the technical merits of being sustained, before any benefit of the tax position can be recognized in the financial statements. Guidance is also provided regarding recognition, classification and disclosure of uncertain tax positions. As of December 31, 2023 and 2022, the amount of unrecognized tax benefits related to NOL carryforwards, tax credit carryforwards, and tax liabilities associated with uncertain tax positions was $68 million and $69 million, respectively. As of December 31, 2023, $24 million is related to state tax receivables not expected to be recovered, $10 million is related to a liability for tax credits taken, and the remainder is related to NOL carryforwards. As of December 31, 2022, $29 million is related to state tax receivables not expected to be recovered, $4 million is related to tax credit carryforwards, and the remainder is related to NOL carryforwards. If recognized, $34 million of the uncertain tax positions identified would have an effect on the effective tax rate. As of December 31, 2023 and 2022, we had no amounts accrued for interest related to these uncertain tax positions. We recognize interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Unrecognized tax benefits at beginning of period	$ 69	$ 74	$ 74	$ 74
Additions based on tax positions related to the current year	3	2	—	—
Additions to tax positions of prior years	3	2	—	—
Settlements	(5)	—	—	—
Expiration of the applicable statute of limitations	—	—	—	—
Reductions to tax positions of prior years	(2)	(9)	—	—
Unrecognized tax benefits at end of period	$ 68	$ 69	$ 74	$ 74

Our federal and state income tax returns are subject to examination by federal and state tax authorities. Our tax years 2020 through 2023 remain open for all purposes of examination by the IRS as well as the Vine 2020 federal income tax return and the Vine short period return for January 1, 2021 through November 1, 2021. However, certain earlier tax years remain open for adjustment to the extent of their NOL carryforwards available for future utilization.

In addition, tax years 2020 through 2023 as well as certain earlier years remain open for examination by state tax authorities. We do not anticipate that the outcome of any federal or state audit will have a significant impact on our financial position or results of operations.

12. Equity

New Common Stock

As discussed in Note 2, on the Effective Date, we issued an aggregate of 97,907,081 shares of New Common Stock, par value $0.01 per share, to the holders of allowed claims, and 2,092,918 shares of New Common Stock were reserved for future distributions under the Plan. During the 2023, 2022 and 2021 Successor Periods, 12,089, 439,370 and 864,090 reserved shares, respectively, were issued to resolve allowed General Unsecured Claims.

On November 1, 2021, we completed the Vine Acquisition and issued 18,709,399 shares of New Common Stock. On March 9, 2022, we completed the Marcellus Acquisition and issued 9,442,185 shares of New Common Stock. See further discussion of both acquisitions in Note 4.

Dividends

In May 2021, we initiated a new annual dividend on our shares of common stock, expected to be paid quarterly. We declared the first quarterly dividend on our New Common Stock in the second quarter of 2021, which consisted of a base dividend per share. In March 2022, we adopted a variable return program that resulted in the payment of an additional variable dividend equal to the sum of Adjusted Free Cash Flow from the prior quarter less the base quarterly dividend, multiplied by 50%. The following table summarizes our dividend payments in the 2023, 2022 and 2021 Successor Periods:

	Base	Variable	Rate Per Share	Total
2023:				
First Quarter	$ 0.55	$ 0.74	$ 1.29	$ 175
Second Quarter	$ 0.55	$ 0.63	$ 1.18	$ 160
Third Quarter	$ 0.575	$ —	$ 0.575	$ 77
Fourth Quarter	$ 0.575	$ —	$ 0.575	$ 75
2022:				
First Quarter	$ 0.4375	$ 1.33	$ 1.7675	$ 210
Second Quarter	$ 0.50	$ 1.84	$ 2.34	$ 298
Third Quarter	$ 0.55	$ 1.77	$ 2.32	$ 280
Fourth Quarter	$ 0.55	$ 2.61	$ 3.16	$ 424
2021:				
Second Quarter	$ 0.34375	$ —	$ 0.34375	$ 34
Third Quarter	$ 0.34375	$ —	$ 0.34375	$ 33
Fourth Quarter	$ 0.4375	$ —	$ 0.4375	$ 52

On February 20, 2024, we declared a base quarterly dividend payable of $0.575 per share, which will be paid on March 26, 2024 to stockholders of record at the close of business on March 7, 2024.

Share Repurchase Program

As of December 2, 2021, the Company was authorized to purchase up to $1.0 billion of the Company's common stock and/or warrants under a share repurchase program, and in March 2022, we commenced our share repurchase program. In June 2022, our Board of Directors authorized an expansion of the share repurchase program by $1.0 billion, bringing the total authorized share repurchase amount to $2.0 billion for stock and/or warrants. The share repurchase program expired on December 31, 2023.

The table below presents the shares purchased under our share repurchase program.

	Shares Purchased (thousands)	Dollar Value of Shares Purchased	Average Price Per Share
2022			
First Quarter	1,000	$ 83	$ 82.98
Second Quarter	5,812	$ 515	$ 88.67
Third Quarter	750	$ 69	$ 92.14
Fourth Quarter	4,105	$ 406	$ 98.90
2023			
First Quarter	793	$ 60	$ 74.95
Second Quarter	1,444	$ 115	$ 78.77
Third Quarter	1,509	$ 130	$ 86.16
Fourth Quarter	627	$ 52	$ 82.03
Total to date	16,040	$ 1,430	

The repurchased shares of common stock were retired and recorded as a reduction to common stock and retained earnings. All share repurchases made after January 1, 2023 are subject to a 1% excise tax on share repurchases, as enacted under the Inflation Reduction Act of 2022. We are able to net this 1% excise tax on share repurchases against certain issuance of shares of our common stock. The impact of this 1% excise tax was immaterial during the 2023 Successor Period.

Warrants

	Class A Warrants	Class B Warrants	Class C Warrants[(a)]
Outstanding as of February 10, 2021	11,111,111	12,345,679	9,768,527
Converted into New Common Stock	(254,259)	(32,406)	(10,603)
Issued for General Unsecured Claims	—	—	1,630,447
Outstanding as of December 31, 2021	10,856,852	12,313,273	11,388,371
Converted into New Common Stock[(b)]	(1,609,641)	(29,679)	(959,247)
Converted in warrant exchange offer[(b)]	(4,752,207)	(7,879,030)	(7,252,004)
Issued for General Unsecured Claims	—	—	829,109
Outstanding as of December 31, 2022	4,495,004	4,404,564	4,006,229
Converted into New Common Stock[(b)]	(247,389)	(1,500)	(5,581)
Issued for General Unsecured Claims	—	—	22,835
Outstanding as of December 31, 2023	4,247,615	4,403,064	4,023,483

(a) As of December 31, 2023, we had 1,466,502 of reserved Class C Warrants.

(b) During the 2023 Successor Period, we issued 221,952 common shares as a result of Warrant exercises. During the 2022 Successor Period, we issued 18,408,228 common shares as a result of Warrant exercises, inclusive of the shares issued as part of the Warrant exchange offers described below.

As discussed in Note 2, on the Effective Date, we issued Class A, Class B and Class C Warrants that were initially exercisable for one share of New Common Stock per Warrant at initial exercise prices of $27.63, $32.13 and $36.18 per share, respectively, subject to adjustments pursuant to the terms of the Warrants. The Warrants are exercisable from the Effective Date until February 9, 2026. The Warrants contain customary anti-dilution adjustments in the event of any stock split, reverse stock split, reclassification, stock dividend or other distributions. The exercise prices of the Warrants were adjusted to prevent the dilution of rights for the effects of the quarterly dividend distribution on December 6, 2023, and the adjusted exercise prices are $23.25, $27.04, and $30.45 per share for the Class A, Class B and Class C Warrants, respectively. Additionally, we have recalculated the number of shares of New Common Stock issuable upon the exercise of each of the Class A, Class B and Class C Warrants, respectively, and as a result, 1.22 shares are issuable upon the exercise of a Class A, Class B or Class C Warrant.

On August 18, 2022, we announced exchange offers relating to our outstanding Class A Warrants, Class B Warrants and Class C Warrants. The exchange offers expired on October 7, 2022 and resulted in the issuance of 16,305,984 shares of our New Common Stock in exchange for the cancellation of (i) 4,752,207 Class A Warrants, (ii) 7,879,030 Class B Warrants and (iii) 7,252,004 Class C Warrants. Under the exchange offers, the Warrants were exchanged in a cashless transaction and were converted to shares of our New Common Stock at a ratio of 0.8636 for Class A Warrants, 0.8224 for Class B Warrants and 0.7890 for Class C Warrants, respectively. As the fair value of the New Common Stock issued was greater than the fair value of the Warrants tendered in the exchange offers due to stated exchange premiums, we recorded a non-cash deemed dividend of $67 million. Such fair values were determined using our stock price that is considered a Level 1 input.

Chapter 11 Proceedings

Upon our emergence from Chapter 11 on February 9, 2021, as discussed in Note 2, Predecessor common stock and preferred stock were canceled and released under the Plan without receiving any recovery on account thereof.

13. Share-Based Compensation

Successor Share-Based Compensation

As of the Effective Date, the Board adopted the LTIP with a share reserve equal to 6,800,000 shares of New Common Stock. The LTIP provides for the grant of restricted stock units ("RSUs"), restricted stock awards, stock options, stock appreciation rights, performance awards and other stock awards to the Company's employees and non-employee directors.

Restricted Stock Units. In the 2023, 2022 and 2021 Successor Periods, we granted RSUs to employees and non-employee directors under the LTIP, which will vest over a three-year to five-year period and one-year period, respectively. The fair value of RSUs is based on the closing sales price of our common stock on the date of grant, and compensation expense is recognized ratably over the requisite service period. A summary of the changes in unvested RSUs is presented below:

	Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share
	(in thousands)	
Unvested as of February 10, 2021	—	$ —
Granted [a]	1,202	$ 52.60
Vested [a]	(377)	$ 65.66
Forfeited	(50)	$ 44.37
Unvested as of December 31, 2021	775	$ 46.77
Granted	666	$ 81.87
Vested	(300)	$ 48.11
Forfeited	(184)	$ 56.54
Unvested as of December 31, 2022	957	$ 68.91
Granted	440	$ 72.25
Vested	(329)	$ 61.66
Forfeited	(128)	$ 68.42
Unvested as of December 31, 2023	940	$ 73.08

(a) Due to the Vine Acquisition, each Vine restricted stock unit was converted into a Company restricted stock unit. As a result, approximately 430 thousand Vine restricted stock units were converted to Company restricted stock units, of which approximately 375 thousand restricted stock units were accelerated. We recognized the accelerated share-based compensation expense related to these awards in other operating expense (income), net on our consolidated statements of operations.

The aggregate intrinsic value of RSUs that vested during the 2023, 2022 and 2021 Successor Periods was approximately $25 million, $26 million and $25 million, respectively, based on the stock price at the time of vesting.

As of December 31, 2023, there was approximately $45 million of total unrecognized compensation expense related to unvested RSUs. The expense is expected to be recognized over a weighted average period of approximately 2.19 years.

Performance Share Units. In the 2023, 2022 and 2021 Successor Periods, we granted performance share units ("PSUs") to senior management under the LTIP, which will generally vest over a three-year period and will be settled in shares. The performance criteria include total shareholder return ("TSR") and relative TSR ("rTSR") and could result in a total payout between 0% - 200% of the target units. For the PSUs granted in 2021, the performance criteria also include share price hurdles which could result in a total payout between 0% - 100% of the target units. The fair value of the PSUs was measured on the grant date using a Monte Carlo simulation, and compensation expense is recognized ratably over the requisite service period because these awards depend on a combination of service and market criteria.

The following tables present the assumptions used in the valuation of the PSUs granted in the 2023, 2022 and 2021 Successor Periods.

2023 PSU Awards

Assumption	**TSR, rTSR**
Risk-free interest rate	3.85 %
Volatility	64.4 %

2022 PSU Awards

Assumption	**TSR, rTSR**
Risk-free interest rate	2.00 %
Volatility	70.2 %

2021 PSU Awards

Assumption	**TSR, rTSR**	**Share Price Hurdle**
Risk-free interest rate	0.23 %	0.30 %
Volatility	71.4 %	68.4 %

A summary of the changes in unvested PSUs is presented below:

	Unvested Performance Share Units	**Weighted Average Grant Date Fair Value Per Share**
	(in thousands)	
Unvested as of February 10, 2021	—	$ —
Granted	201	$ 64.41
Vested	(9)	$ 38.95
Forfeited	(9)	$ 55.42
Unvested as of December 31, 2021	183	$ 66.12
Granted	133	$ 109.65
Vested	—	$ —
Forfeited	(40)	$ 57.48
Unvested as of December 31, 2022	276	$ 88.28
Granted	131	$ 78.78
Vested	—	$ —
Forfeited	(13)	$ 68.77
Unvested as of December 31, 2023	394	$ 85.78

The aggregate intrinsic value of PSUs that vested during the 2021 Successor Period was approximately $0.6 million based on the stock price at the time of vesting.

As of December 31, 2023, there was approximately $15 million of total unrecognized compensation expense related to unvested PSUs. The expense is expected to be recognized over a weighted average period of approximately 1.68 years.

Predecessor Share-Based Compensation

Our Predecessor share-based compensation program consisted of restricted stock, stock options and PSUs granted to employees and restricted stock granted to non-employee directors under our long-term incentive plans. The restricted stock and stock options were equity-classified awards and the PSUs were liability-classified awards.

As discussed in Note 2, on the Effective Date, our Predecessor common stock was canceled and New Common Stock was issued. Accordingly, our then existing share-based compensation awards were also canceled, which resulted in the recognition of any previously unamortized expense related to the canceled awards on the date of cancellation. Share-based compensation for the Predecessor and Successor Periods is not comparable.

RSU and PSU Compensation.

We recognized the following compensation costs, net of actual forfeitures, related to RSUs and PSUs for the periods presented:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
General and administrative expenses	$ 29	$ 19	$ 7	$ 3
Natural gas and oil properties	6	4	2	—
Production expense	4	3	2	—
Total RSU and PSU compensation	$ 39	$ 26	$ 11	$ 3
Related income tax benefit	$ 7	$ 6	$ —	$ —

14. Employee Benefit Plans

Our qualified 401(k) profit sharing plan ("401(k) Plan") is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the IRS. We match employee contributions dollar for dollar (subject to a maximum contribution of 6% of an employee's base salary and performance bonus) in cash. In April 2021, the 401(k) match was changed from 15% to 6%. In addition to our employer match contributions, in 2022 we commenced a discretionary fixed dollar contribution benefit for all employees, paid quarterly, which is based upon a calculation of 1% of Adjusted Free Cash Flow less the base quarterly dividend. This discretionary fixed dollar contribution is subject to an annual maximum contribution of $15,000 per employee. We contributed $13 million, $22 million, $8 million and $2 million to the 401(k) Plan in the 2023 Successor Period, 2022 Successor Period, 2021 Successor Period and 2021 Predecessor Period, respectively.

15. Derivative and Hedging Activities

We use derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. All of our natural gas and oil derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty. None of our open natural gas and oil derivative instruments were designated for hedge accounting as of December 31, 2023 and 2022.

As of December 31, 2022, approximately $65 million of derivative liabilities (notional volume of 9.6 Bcf of natural gas and notional volume of 4.8 MMBbls of oil) were classified as liabilities held for sale. These derivative instruments were novated to WildFire Energy I LLC upon completion of the sale of a portion of our Eagle Ford assets on March 20, 2023. See Note 4 for more details.

Natural Gas and Oil Derivatives

As of December 31, 2023 and 2022, our natural gas and oil derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and swap options.
- *Options*: We have bought and sold call options in exchange for a premium. At the time of settlement, if the market price exceeded the fixed price of the call option, we paid the counterparty the excess on sold call options and received the excess on bought call options. If the market price settled below the fixed price of the call option, no payment was due from either party.
- *Collars*: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars included the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminated the counterparty’s downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

Contingent Consideration Arrangement

In November 2023, we sold the final portion of our Eagle Ford assets to SilverBow. As part of the divestiture agreement, SilverBow has agreed to pay Chesapeake an additional contingent payment of $25 million should WTI NYMEX prices average between $75 and $80 per barrel or $50 million should WTI NYMEX prices average above $80 per barrel during the year following the close of the transaction. All changes in fair value are recognized as a gain or loss in earnings in the period they occur within natural gas and oil derivatives in our consolidated statements of operations. During the 2023 Successor Period, we recorded $9 million of unrealized losses related to the contingent consideration arrangement.

The estimated fair values of our natural gas and oil derivative instrument assets (liabilities) as of December 31, 2023 and 2022 are provided below:

	Successor			
	December 31, 2023		December 31, 2022	
	Notional Volume	Fair Value	Notional Volume	Fair Value
Natural gas (Bcf):				
Fixed-price swaps	343	$ 188	382	$ (494)
Collars	558	497	721	49
Three-way collars	—	—	4	(2)
Call options	—	—	18	(22)
Basis protection swaps	578	2	652	(32)
Total natural gas	1,479	687	1,777	(501)
Oil (MMBbls):				
Fixed-price swaps	—	—	1	(32)
Collars	—	—	2	7
Basis protection swaps	—	—	6	1
Total oil	—	—	9	(24)
Contingent Consideration:				
Eagle Ford divestiture		12		—
Total estimated fair value		$ 699		$ (525)

Effect of Derivative Instruments – Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the consolidated balance sheets as of December 31, 2023 and 2022 on a gross basis and after same-counterparty netting:

	Gross Fair Value[a]	Amounts Netted in the Consolidated Balance Sheets	Net Fair Value Presented in the Consolidated Balance Sheets
Successor			
As of December 31, 2023			
Commodity Contracts:			
Short-term derivative asset	$ 661	$ (36)	$ 625
Long-term derivative asset	101	(27)	74
Short-term derivative liability	(39)	36	(3)
Long-term derivative liability	(36)	27	(9)
Contingent Consideration:			
Short-term derivative asset	12	—	12
Total derivatives	$ 699	$ —	$ 699
As of December 31, 2022			
Commodity Contracts:			
Short-term derivative asset	$ 200	$ (166)	$ 34
Long-term derivative asset	87	(40)	47
Short-term derivative liability	(598)	166	(432)
Long-term derivative liability	(214)	40	(174)
Total derivatives	$ (525)	$ —	$ (525)

(a) These financial assets (liabilities) are measured at fair value on a recurring basis utilizing significant other observable inputs; see further discussion on fair value measurements below.

Fair Value

The fair value of our commodity contracts derivatives is based on third-party pricing models, which utilize inputs that are either readily available in the public market, such as natural gas, oil and NGL forward curves and discount rates, or can be corroborated from active markets or broker quotes, and, as such, are classified as Level 2. These values are compared to the values given by our counterparties for reasonableness. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives. The valuation of the contingent consideration is based on an option pricing model using significant Level 2 inputs that include quoted future commodity prices based on active markets.

Credit Risk Considerations

Our derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we only enter into commodity contracts derivatives with counterparties that are highly rated or deemed by us to have acceptable credit strength and deemed by management to be competent and competitive market-makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2023, our commodity contracts derivative instruments were spread among 15 counterparties.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that were also lenders (or affiliates of lenders) under our New Credit Facility. The contracts entered into with these counterparties are secured by the same collateral that secures the revolving credit facility. The counterparties' obligations must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us exceed defined thresholds. As of December 31, 2023, we did not have any cash or letters of credit posted as collateral for our commodity derivatives.

Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)

A reconciliation of the changes in accumulated other comprehensive income (loss) in our consolidated statements of stockholders' equity related to our cash flow hedges is presented below:

	Predecessor	
	Period from January 1, 2021 through February 9, 2021	
	Before Tax	After Tax
Balance, beginning of period	$ (12)	$ 45
Losses reclassified to income[(a)]	3	3
Fresh start adjustments	9	9
Elimination of tax effects	—	(57)
Balance, end of period	$ —	$ —

(a) These losses were included as a component of total natural gas and oil derivatives.

Our accumulated other comprehensive loss balance represented the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months had yet to occur. The remaining deferred gain or loss amounts were to be recognized in earnings in the month for which the original contract months were to occur. In connection with our adoption of fresh start accounting, we recorded a fair value adjustment to eliminate the accumulated other comprehensive income related to hedging settlements including the elimination of tax effects. See Note 3 for a discussion of fresh start accounting adjustments. We did not have any changes or items impacting other comprehensive income for the 2023, 2022 or 2021 Successor Periods.

16. Capitalized Exploratory Well Costs

A summary of the changes in our capitalized exploratory well costs for the periods presented is detailed below. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Balance, beginning of period	$ 10	$ 14	$ —	$ —
Additions pending the determination of proved reserves	—	1	24	—
Divestitures and other	(10)	—	—	—
Reclassifications to proved properties	—	—	(10)	—
Charges to exploration expense	—	(5)	—	—
Balance, end of period[(a)]	$ —	$ 10	$ 14	$ —

(a) Our capitalized exploratory well costs balance as of December 31, 2022, consisted of one project for which we had suspended exploratory well costs capitalized for a period greater than one year. During the 2023 Successor Period, this project was divested.

We had no projects with suspended exploratory well costs capitalized for a period greater than one year as of December 31, 2021.

17. Other Property and Equipment

A summary of other property and equipment held for use and the estimated useful lives thereof is as follows:

	Successor		Estimated Useful Life
	December 31, 2023	December 31, 2022	(in years)
Buildings and improvements	$ 316	$ 325	10 - 39
Computer equipment	94	92	5
Land	28	32	
Other	59	51	5 - 20
Total other property and equipment, at cost	497	500	
Less: accumulated depreciation	(90)	(58)	
Total other property and equipment, net	$ 407	$ 442	

18. Investments

Momentum Sustainable Ventures LLC. During the fourth quarter of 2022, Chesapeake entered into an agreement with Momentum Sustainable Ventures LLC to build a new natural gas gathering pipeline and carbon capture and sequestration project ("CCUS"), which will gather natural gas produced in the Haynesville Shale for re-delivery to Gulf Coast markets, including LNG export. The pipeline is expected to have an initial capacity of 1.7 Bcf/d expandable to 2.2 Bcf/d. The carbon capture portion of the project anticipates capturing and permanently sequestering up to 2.0 million tons per annum of CO2. The natural gas gathering pipeline is projected for a potential in-service date in 2025, and the carbon sequestration portion of the project is subject to regulatory approvals. We have a 35% interest in the project and estimate approximately $112 million remaining in our commitment to the project. We have accounted for this investment as an equity method investment, and its carrying value, which is reflected within other long-term assets on the consolidated balance sheets, was $238 million and $18 million as of December 31, 2023 and December 31, 2022, respectively. During the 2023 and 2022 Successor Periods, the activity related to our investment in Momentum Sustainable Ventures LLC had an immaterial impact on our consolidated statements of operations.

19. Exploration Expense

During the 2023 Successor Period, exploration expense charges of $27 million were primarily the result of $12 million of non-cash impairment charges in unproved properties and $11 million of geological and geophysical expense. During the 2022 Successor Period, exploration expense charges of $23 million were primarily the result of non-cash impairment charges in unproved properties of $8 million, $6 million of charges related to dry hole expense and $6 million of geological and geophysical expense. We did not have material exploration expenses during the 2021 Successor Period or 2021 Predecessor Period.

20. Asset Retirement Obligations

The components of the change in our asset retirement obligations are shown below:

	Successor	
	Year Ended December 31, 2023	Year Ended December 31, 2022
Asset retirement obligations, beginning of period	$ 335	$ 360
Additions[(a)]	9	53
Revisions[(b)]	(9)	16
Settlements and disposals[(c)]	(75)	(54)
Held for sale[(d)]	—	(57)
Accretion expense	16	17
Asset retirement obligations, end of period	276	335
Less current portion	11	12
Asset retirement obligations, long-term	$ 265	$ 323

(a) During the 2022 Successor Period, approximately $27 million of additions relate to the Marcellus Acquisition. See Note 4 for further discussion of this transaction.

(b) Revisions primarily represent changes in the present value of liabilities resulting from changes in estimated costs and economic lives of producing properties.

(c) During the 2023 Successor Period, approximately $64 million of disposals related to the divestitures of our Eagle Ford assets. During the 2022 Successor Period, approximately $47 million of disposals related to the divestiture of our Powder River Basin assets. See Note 4 for further discussion of these transactions.

(d) As of December 31, 2022, approximately $57 million of asset retirement obligations associated with the sale of a portion of our Eagle Ford assets were reclassified as other current liabilities held for sale.

21. Subsequent Events

On January 10, 2024, Chesapeake and Southwestern Energy Company (“Southwestern”) entered into an all-stock merger agreement (“Southwestern Merger”). Southwestern is an independent energy company engaged in development, exploration and production activities, including related marketing activities, within its operating areas in the Marcellus and Haynesville shale plays. Pursuant to the terms of the merger agreement, at the effective time of the Southwestern Merger, each eligible share of Southwestern common stock issued and outstanding immediately prior to the effective time will be automatically converted into the right to receive 0.0867 of a share of Chesapeake’s common stock. Our Board of Directors and the Board of Directors of Southwestern both approved the merger agreement. Subject to the approval of our shareholders and Southwestern shareholders, regulatory approvals and the satisfaction or waiver of other customary closing conditions, the Southwestern Merger is targeted to close in the second quarter of 2024.

Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities (unaudited)

Certain reserves and production information was previously disclosed in a per barrel of oil equivalent. As the majority of our production profile consists of natural gas, we have converted this information, including prior periods, from a per barrel of oil equivalent, to a per one thousand cubic feet of natural gas equivalent, referred to, on such a converted basis, as per Mcfe.

Net Capitalized Costs

Capitalized costs related to our natural gas, oil and NGL producing activities are summarized as follows:

	Successor	
	December 31, 2023	December 31, 2022
Natural gas and oil properties:		
Proved	$ 11,468	$ 11,096
Unproved	1,806	2,022
Total	13,274	13,118
Less accumulated depreciation, depletion and amortization	(3,584)	(2,373)
Net capitalized costs	$ 9,690	$ 10,745

Unproved properties as of December 31, 2023 and 2022, consisted mainly of leasehold acquired through our Vine Acquisition and Marcellus Acquisition. We will continue to evaluate our unproved properties, and although the timing of the ultimate evaluation or disposition of the properties cannot be determined, we can expect the majority of our unproved properties not held by production to be transferred into the amortization base over the next five years.

Costs Incurred in Natural Gas and Oil Property Acquisition, Exploration and Development

Costs incurred in natural gas and oil property acquisition, exploration and development, including capitalized interest and asset retirement costs, are summarized as follows:

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Acquisition of properties[(a)]:				
Proved properties	$ 10	$ 2,321	$ 2,183	$ —
Unproved properties	52	795	1,121	—
Exploratory costs	15	15	31	—
Development costs	1,721	1,918	717	58
Costs incurred	$ 1,798	$ 5,049	$ 4,052	$ 58

(a) Includes $2.31 billion and $0.79 billion of proved and unproved property acquisitions, respectively, related to our Marcellus Acquisition in 2022. Includes $2.18 billion and $1.10 billion of proved and unproved property acquisitions, respectively, related to our Vine Acquisition in 2021.

Results of Operations from Natural Gas, Oil and NGL Producing Activities

The following table includes revenues and expenses associated directly with our natural gas, oil and NGL producing activities for the periods presented. It does not include any derivative activity, interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas, oil and NGL operations.

	Successor			Predecessor
	Year Ended December 31, 2023	Year Ended December 31, 2022	Period from February 10, 2021 through December 31, 2021	Period from January 1, 2021 through February 9, 2021
Natural gas, oil and NGL sales	$ 3,547	$ 9,892	$ 4,401	$ 398
Production expenses	(356)	(475)	(297)	(32)
Gathering, processing and transportation expenses	(853)	(1,059)	(780)	(102)
Severance and ad valorem taxes	(167)	(242)	(158)	(18)
Exploration	(27)	(23)	(7)	(2)
Depletion and depreciation	(1,478)	(1,703)	(882)	(64)
Accretion of asset retirement obligations	(16)	(17)	(11)	(1)
Imputed income tax provision[(a)]	(152)	(1,440)	(535)	(42)
Results of operations from natural gas, oil and NGL producing activities	$ 498	$ 4,933	$ 1,731	$ 137

(a) The imputed income tax provision is hypothetical (at the statutory tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision (benefit) will be payable (receivable).

Natural Gas, Oil and NGL Reserve Quantities

Our petroleum engineers estimated all of our proved reserves as of December 31, 2023, 2022 and 2021. Independent petroleum engineering firm Netherland, Sewell & Associates, Inc. audited our total proved reserves as of December 31, 2023.

Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil and NGL 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules, the price is calculated using 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 the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. A project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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. 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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The information provided below on our natural gas, oil and NGL reserves is presented in accordance with regulations prescribed by the SEC. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. These changes could be material and could occur in the near term.

Presented below is a summary of changes in estimated proved reserves for the periods presented:

	Natural Gas	Oil	NGL	Total
	(Bcf)	(MMBbl)	(MMBbl)	(Bcfe)
December 31, 2023				
Proved reserves, beginning of period (Successor)	11,369	198.4	73.9	13,002
Extensions, discoveries and other additions	415	—	—	415
Revisions of previous estimates	(325)	—	—	(325)
Production	(1,266)	(7.7)	(3.8)	(1,335)
Sale of reserves-in-place	(563)	(190.7)	(70.1)	(2,127)
Purchase of reserves-in-place	58	—	—	58
Proved reserves, end of period (Successor)	9,688	—	—	9,688
Proved developed reserves:				
Beginning of period (Successor)	7,385	157.2	58.9	8,681
End of period (Successor)	6,363	—	—	6,363
Proved undeveloped reserves:				
Beginning of period (Successor)	3,984	41.2	15.0	4,321
End of period[(a)] (Successor)	3,325	—	—	3,325
December 31, 2022				
Proved reserves, beginning of period (Successor)	7,824	209.7	82.0	9,573
Extensions, discoveries and other additions	60	2.1	1.5	82
Revisions of previous estimates	1,989	22.5	5.0	2,155
Production	(1,308)	(19.4)	(6.0)	(1,461)
Sale of reserves-in-place	(122)	(16.5)	(8.6)	(273)
Purchase of reserves-in-place	2,926	—	—	2,926
Proved reserves, end of period (Successor)	11,369	198.4	73.9	13,002
Proved developed reserves:				
Beginning of period (Successor)	4,246	165.7	61.7	5,610
End of period (Successor)	7,385	157.2	58.9	8,681
Proved undeveloped reserves:				
Beginning of period (Successor)	3,578	44.0	20.3	3,963
End of period[(a)] (Successor)	3,984	41.2	15.0	4,321

	Natural Gas (Bcf)	Oil (MMBbl)	NGL (MMBbl)	Total (Bcfe)
December 31, 2021				
Proved reserves, beginning of period (Predecessor)	3,530	161.3	52.0	4,809
Extensions, discoveries and other additions	1,744	41.0	16.9	2,091
Revisions of previous estimates	1,522	33.3	21.1	1,848
Production	(807)	(25.9)	(8.0)	(1,010)
Sale of reserves-in-place	—	—	—	—
Purchase of reserves-in-place	1,835	—	—	1,835
Proved reserves, end of period (Successor)	7,824	209.7	82.0	9,573
Proved developed reserves:				
Beginning of period (Predecessor)	3,196	158.1	51.4	4,452
End of period (Successor)	4,246	165.7	61.7	5,610
Proved undeveloped reserves:				
Beginning of period (Predecessor)	334	3.2	0.6	357
End of period[(a)] (Successor)	3,578	44.0	20.3	3,963

(a) As of December 31, 2023, 2022 and 2021, there were no PUDs that had remained undeveloped for five years or more.

During 2023, we divested 2,127 Bcfe, primarily related to our Eagle Ford divestitures. We recorded extensions and discoveries of 415 Bcfe, primarily related to new PUDs and previously unproved producing wells in the Upper Marcellus and Bossier Shales. We recorded 325 Bcfe of downward revisions of previous estimates, with 1,623 Bcfe of downward revisions due to lower natural gas, oil and NGL prices in 2023, partially offset by 1,298 Bcfe of non-price related positive revisions. The non-price revisions primarily consisted of 1,517 Bcfe from new PUDs and producing wells added in previously proved areas, 469 Bcfe of positive revisions to previously recorded PUD reserves primarily due to expected longer laterals in both Marcellus and Haynesville, partially offset by downward revisions of 451 Bcfe due to development plan and other changes in Marcellus and Haynesville, and a downward revision of 237 Bcfe on proved developed reserves related to aligning forecasts with latest production trends. The natural gas, oil and NGL prices used in computing our reserves as of December 31, 2023, were $2.64 per Mcf, $78.22 per Bbl and $28.61 per Bbl, respectively, before basis differential adjustments.

During 2022, we acquired 2,926 Bcfe, primarily related to the Marcellus Acquisition. We recorded extensions and discoveries of 82 Bcfe, primarily related to new PUDs and previously unproved producing wells in emerging plays. We recorded 2,155 Bcfe of upward revisions of previous estimates, which consisted of 866 Bcfe of revisions to PUDs, primarily due to development plan optimization through prioritizing longer laterals and multi-well pad development in the Haynesville, 1,156 Bcfe of revisions to existing or new proved developed properties, primarily due to performance and 133 Bcfe of revisions due to higher natural gas, oil and NGL prices in 2022. The natural gas, oil and NGL prices used in computing our reserves as of December 31, 2022, were $6.36 per Mcf, $93.67 per Bbl and $43.58 per Bbl, respectively, before basis differential adjustments.

During 2021, we acquired 1,835 Bcfe, primarily related to the Vine Acquisition. We recorded extensions and discoveries of 2,091 Bcfe following our emergence from bankruptcy on February 9, 2021, and certainty regarding our ability to finance the development of our proved reserves over a five-year period. We recorded 1,848 Bcfe of upward revisions of previous estimates, which consisted of 1,284 Bcfe due to lateral length adjustments, performance and updates to our five-year development plan and 564 Bcfe due to higher natural gas, oil and NGL prices in 2021. The natural gas, oil and NGL prices used in computing our reserves as of December 31, 2021, were $3.60 per Mcf, $66.56 per Bbl and $35.81 per Bbl, respectively, before basis differential adjustments.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards Codification Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2023, 2022 and 2021 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of natural gas, oil and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved natural gas, oil and NGL reserves based on the standardized measure:

	Years Ended December 31,		
	2023	2022	2021
Future cash inflows	$ 14,659 (a)	$ 76,626 (b)	$ 33,700 (c)
Future production costs	(3,326)	(10,177)	(6,735)
Future development costs	(2,779) (d)	(5,343) (e)	(3,687) (f)
Future income tax provisions	(174)	(10,440)	(2,254)
Future net cash flows	8,380	50,666	21,024
Less effect of a 10% discount factor	(3,903)	(24,361)	(8,737)
Standardized measure of discounted future net cash flows	$ 4,477	$ 26,305	$ 12,287

(a) Calculated using prices of $2.64 per Mcf of natural gas, before basis differential adjustments.

(b) Calculated using prices of $6.36 per Mcf of natural gas, $93.67 per Bbl of oil and $43.58 per Bbl of NGL, before basis differential adjustments.

(c) Calculated using prices of $3.60 per Mcf of natural gas, $66.56 per Bbl of oil and $35.81 per Bbl of NGL, before basis differential adjustments.

(d) Included approximately $730 million of future plugging and abandonment costs as of December 31, 2023.

(e) Included approximately $979 million of future plugging and abandonment costs as of December 31, 2022.

(f) Included approximately $846 million of future plugging and abandonment costs as of December 31, 2021.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	Years Ended December 31,		
	2023	2022	2021
Standardized measure, beginning of period[a]	$ 26,305	$ 12,287	$ 3,086
Sales of natural gas and oil produced, net of production costs and gathering, processing and transportation[b]	(2,171)	(8,116)	(3,414)
Net changes in prices and production costs	(23,535)	14,256	6,674
Extensions and discoveries, net of production and development costs	182	251	2,834
Changes in estimated future development costs	346	(1,512)	(459)
Previously estimated development costs incurred during the period	818	690	130
Revisions of previous quantity estimates	(205)	6,697	2,034
Purchase of reserves-in-place	77	7,047	2,807
Sales of reserves-in-place	(7,158)	(402)	—
Accretion of discount	3,270	1,371	309
Net change in income taxes	6,301	(4,972)	(1,423)
Changes in production rates and other	247	(1,292)	(291)
Standardized measure, end of period[a]	$ 4,477	$ 26,305	$ 12,287

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excludes gains and losses on derivatives. Production costs includes severance and ad valorem taxes.

Item 9. ***Changes In and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded as of December 31, 2023 that our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2023 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

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control-Integrated Framework* (2013) in conducting the required assessment of effectiveness of the Company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company’s internal control over financial reporting was effective as of December 31, 2023.

The effectiveness of our internal control over financial reporting as of December 31, 2023 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

/s/ DOMENIC J. DELL'OSSO, JR.

Domenic J. Dell'Osso, Jr.
President and Chief Executive Officer

/s/ MOHIT SINGH

Mohit Singh
Executive Vice President and Chief Financial Officer

February 21, 2024

Item 9B. ***Other Information***

During the three months ended December 31, 2023, no director or officer of the Company adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement”, as each term is defined in Item 408 of Regulation S-K.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

Not applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The names of executive officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2023 (the “2024 Proxy Statement”).

Item 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the 2024 Proxy Statement.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by this Item 12 is incorporated herein by reference to the 2024 Proxy Statement.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information called for by this Item 13 is incorporated herein by reference to the 2024 Proxy Statement.

Item 14. ***Principal Accountant Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the 2024 Proxy Statement.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) The following financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.
3. *Exhibits*. The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
2.1	Fifth Amended Joint Plan of Reorganization of Chesapeake Energy Corporation and its Debtor Affiliates Pursuant to Chapter 11 of the Bankruptcy Code (Exhibit A of the Confirmation Order).	8-K	001-13726	2.1	1/19/2021	
2.2	Agreement and Plan of Merger, dated as of August 10, 2021, by and among Chesapeake Energy Corporation, Hannibal Merger Sub, Inc., Hannibal merger Sub, LLC, Vine Energy Inc. and Vine Energy holdings LLC.	8-K	001-13726	2.1	8/11/2021	
2.3	Partnership Interest Purchase Agreement by and among The Jan & Trevor Rees-Jones Revocable Trust, Rees-Jones Family Holdings, LP, Chief E&D Participants, LP, and Chief E&D (GP) LLC (collectively, as Sellers) and Chesapeake Energy Corporation and its affiliates, dated as of January 24, 2022.	10-K	001-13726	10.36	2/24/2022	
2.4	Membership Interest Purchase Agreement by and among Radler 2000 Limited Partnership and Tug Hill, Inc., together as Sellers, and Chesapeake Energy Corporation and its affiliates, dated as of January 24, 2022.	10-K	001-13726	10.37	2/24/2022	
2.5	Membership Interest Purchase Agreement by and among Radler 2000 Limited Partnership and Tug Hill, Inc., together as Sellers, and Chesapeake Energy Corporation and its affiliates, dated as of January 24, 2022.	10-K	001-13726	10.38	2/24/2022	
2.6*	Agreement and Plan of Merger, dated as of January 10, 2024, among Chesapeake Energy Corporation, Hulk Merger Sub, Inc., Hulk LLC Sub, LLC, and Southwestern Energy Corporation	8-K	001-13726	2.1	1/11/2024	

3.1	Second Amended and Restated Certificate of Incorporation of Chesapeake Energy Corporation.	8-K	001-13726	3.1	2/9/2021
3.2	Second Amended and Restated Bylaws of Chesapeake Energy Corporation.	8-K	001-13726	3.2	2/9/2021
3.3	Certificate of Elimination of Series B Preferred Stock of Chesapeake Energy Corporation.	10-K	001-13726	3.3	3/1/2021
4.1	Description of Securities.	8-A	001-13726	N/A	2/9/2021
10.1	Restructuring Support Agreement, dated June 28, 2020.	8-K	001-13726	10.1	6/29/2020
10.2	Backstop Commitment Agreement, dated June 28, 2020 (Exhibit 4 to the Restructuring Support Agreement).	8-K	001-13726	10.1	6/29/2020
10.3	Registration Rights Agreement, dated as of February 9, 2021, by and among Chesapeake Energy Corporation and the other parties signatory thereto.	8-K	001-13726	10.2	2/9/2021
10.4	Class A Warrant Agreement, dated as of February 9, 2021, between Chesapeake Energy Corporation and Equiniti Trust Company.	8-K	001-13726	10.3	2/9/2021
10.5	Class B Warrant Agreement, dated as of February 9, 2021, between Chesapeake Energy Corporation and Equiniti Trust Company.	8-K	001-13726	10.4	2/9/2021
10.6	Class C Warrant Agreement, dated as of February 9, 2021, between Chesapeake Energy Corporation and Equiniti Trust Company.	8-K	001-13726	10.5	2/9/2021
10.7	Form of Indemnity Agreement.	8-K	001-13726	10.6	2/9/2021
10.8†	Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.7	2/9/2021
10.9	Purchase Agreement, dated as of February 2, 2021, by and among Chesapeake Escrow Issuer LLC, and Goldman Sachs & Co. LLC, RBC Capital Markets, LLC, as representatives of the purchasers signatory thereto, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.10	3/1/2021
10.10	Indenture dated as of February 5, 2021, among Chesapeake Escrow Issuer LLC, as issuer, the guarantors signatory thereto, and Deutsche Bank Trust Company Americas, as Trustee, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.11	3/1/2021
10.11	Joinder Agreement, dated as of February 9, 2021, by and among Chesapeake Energy Corporation and the Guarantors party thereto, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.12	3/1/2021

10.12	First Supplemental Indenture, dated as of February 9, 2021, by and among Chesapeake Energy Corporation, the Guarantors signatory thereto, and Deutsche Bank Trust Company Americas, as Trustee, with respect to 5.5% Senior Notes due 2026 and 5.875% Senior Notes due 2029.	10-K	001-13726	10.13	3/1/2021
10.13†	Amendment to the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.3	4/27/2021
10.14†	Form of Incentive Agreement between Executive Vice President / Senior Vice President and Chesapeake Energy Corporation.	10-K/A	001-13726	10.14	4/30/2021
10.15†	Form of Executive/Employee Restricted Stock Unit Award Agreement for 2021 Long Term Incentive Plan.	10-K	001-13726	10.18	2/24/2022
10.16†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2021 Long Term Incentive Plan.	10-Q	001-13726	10.9	5/13/2021
10.17†	Form of Performance Share Unit Award (Absolute TSR) for 2021 Long Term Incentive Plan	10-Q	001-13726	10.10	8/10/2021
10.18†	Form of Performance Share Unit Award (Relative TSR) for 2021 Long Term Incentive Plan	10-Q	001-13726	10.11	8/10/2021
10.19†	Chesapeake Energy Corporation Executive Severance Plan	8-K	001-13726	10.1	10/12/2021
10.20†	Form of Participation Agreement pursuant to Chesapeake Energy Corporation Executive Severance Plan	8-K	001-13726	10.2	10/12/2021
10.21†	Executive Chairman Agreement by and between Michael Wichterich and Chesapeake Energy Corporation, dated October 11, 2021	8-K	001-13726	10.4	10/12/2021
10.22†	Second Amendment to the Chesapeake Energy Corporation 2021 Long Term Incentive Plan.	8-K	001-13726	10.3	10/12/2021
10.23	Supplemental Indenture, dated as of November 2, 2021, by and among Chesapeake Energy Corporation, the guarantors party thereto and Wilmington Trust, National Association, as Trustee.	8-K	001-13726	4.1	11/2/2021
10.24	Supplemental Indenture, dated as of November 2, 2021, by and among Chesapeake Energy Corporation, the guarantors party thereto and Deutsche Bank Trust Company Americas, as Trustee.	8-K	001-13726	4.2	11/2/2021
10.25	Registration Rights Agreement dated March 9, 2022, by and among the Company and The Jan & Trevor Rees-Jones Revocable Trust, Rees-Jones Family Holdings, LP, Chief E&D Participants, LP, and Chief E&D (GP) LLC.	8-K	001-13726	10.1	3/9/2022

10.26	Registration Rights Agreement dated March 9, 2022, by and among the Company and Radler 2000 Limited Partnership.	8-K	001-13726	10.2	3/9/2022	
10.27	Form of Dealer Manager Agreement in connection with exchange offers for Warrants.	S-4	333-266961	10.34	8/18/2022	
10.28	Form of Tender and Support Agreement, dated September 12, 2022, in connection with exchange offers for Warrant.	S-4/A	333-266961	10.35	9/12/2022	
10.29	Credit Agreement, dated as of December 9, 2022, among Chesapeake Energy Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and other parties thereto.	8-K	001-13726	10.1	12/12/2022	
10.30†	Form of Chesapeake Energy Corporation Executive Letter Agreement	8-K	001-13726	10.1	1/11/2024	
21	Subsidiaries of Chesapeake Energy Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of PricewaterhouseCoopers LLP.					X
23.3	Consent of Netherland, Sewell & Associates, Inc.					X
31.1	Domenic J. Dell'Osso, Jr., President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Mohit Singh, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Domenic J. Dell'Osso, Jr., President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Mohit Singh, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
95.1	Mine Safety Disclosure Exhibit					X
97.1	Chesapeake Energy Corporation Clawback Policy					X
99.1	Audit Letter of Netherland, Sewell & Associates, Inc.					X
101 INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.					X
101 SCH	Inline XBRL Taxonomy Extension Schema Document.					X

101 CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.	X
101 DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.	X
101 LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.	X
101 PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.	X
104	Cover Page Interactive Data file (formatted as Inline XBRL and contained in Exhibit 101).	X

* Schedules have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant hereby undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

† Management contract or compensatory plan or arrangement.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about Chesapeake Energy Corporation or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about Chesapeake Energy Corporation or its business or operations on the date hereof.

Item 16. *Form 10-K Summary*

Not applicable.

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.

CHESAPEAKE ENERGY CORPORATION

Date: February 21, 2024

By: /s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
President and Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Domenic J. Dell'Osso, Jr. his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

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	Capacity	Date
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	President and Chief Executive Officer (Principal Executive Officer)	February 21, 2024
/s/ MOHIT SINGH **Mohit Singh**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 21, 2024
/s/ GREGORY M. LARSON **Gregory M. Larson**	Vice President - Accounting & Controller (Principal Accounting Officer)	February 21, 2024
/s/ MICHAEL WICHTERICH **Michael Wichterich**	Chairman of the Board	February 21, 2024
/s/ TIMOTHY S. DUNCAN **Timothy S. Duncan**	Director	February 21, 2024
/s/ BENJAMIN C. DUSTER, IV **Benjamin C. Duster, IV**	Director	February 21, 2024
/s/ SARAH A. EMERSON **Sarah A. Emerson**	Director	February 21, 2024
/s/ MATTHEW M. GALLAGHER **Matthew M. Gallagher**	Director	February 21, 2024
/s/ BRIAN STECK **Brian Steck**	Director	February 21, 2024

Company Information

BOARD OF DIRECTORS

Michael A. Wichterich
Chairman of the Board
Chesapeake Energy Corporation
Founder, Chief Executive Officer and Chairman
Three Rivers Operating Company LLC

Domenic J. ("Nick") Dell'Osso, Jr.
President and Chief Executive Officer
Chesapeake Energy Corporation

Timothy S. Duncan [1,2,4]
President, Chief Executive Officer and Director
Talos Energy Inc.

Benjamin C. Duster, IV [1,2]
Founder and Chief Executive Officer
Cormorant IV Corporation, LLC
Chief Financial Officer
Mobile Tech, Inc.

Sarah A. Emerson [3,4]
President
Energy Security Analysis, Inc.
Managing Principal
ESAI Energy, LLC

Matthew M. Gallagher [1,3]
President and Chief Executive Officer
Greenlake Energy, LLC
Venture Partner
NGP Energy Capital, LLC

Brian Steck [2,4]
Co-Founder and Chief Executive Officer
WhiteOwl Energy LLC

(1) Audit Committee
(2) Compensation Committee
(3) Nominating and Corporate Governance Committee
(4) Environmental and Social Governance Committee

MANAGEMENT TEAM

Domenic J. ("Nick") Dell'Osso, Jr.
President, Chief Executive Officer and Director

Benjamin E. Russ
Executive Vice President – General Counsel and Corporate Secretary

Mohit Singh
Executive Vice President and Chief Financial Officer

Joshua J. Viets
Executive Vice President and Chief Operating Officer

INVESTOR INFORMATION

Company financial information, public disclosures and other information are available through Chesapeake's website at chk.com. We will promptly deliver free of charge, upon request, a copy of the Annual Report on Form 10-K to any shareholder requesting a copy. Requests should be directed to Investor Relations at our corporate headquarters address.

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the National Association of Securities Dealers Automated Quotations (Nasdaq) under the symbol "CHK." As of April 8, 2024, the record date for our 2024 Annual Meeting of Shareholders, there were approximately 131,048,149 beneficial owners of our common stock.

INDEPENDENT PUBLIC ACCOUNTANTS

PricewaterhouseCoopers LLP
211 North Robinson Avenue, Suite 1400
Oklahoma City, OK 73102
(405) 290-7200

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
EQ Shareowner Services
P.O. Box 64874
St. Paul, MN 55164-0874
(800) 468-9716
(651) 450-4064 (outside the United States)
shareowneronline.com

TRUSTEE FOR THE COMPANY'S SENIOR NOTES

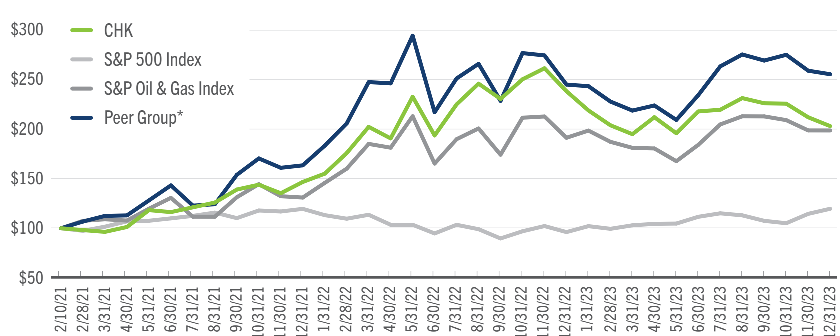
Deutsche Bank Trust Company Americas
60 Wall Street, 37th Floor
New York, NY 10005
db.com

FORWARD-LOOKING STATEMENTS

The letter to shareholders includes "forward-looking statements" related to our business strategy and objectives for future operations. Although we believe there is a reasonable basis for these forward-looking statements, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2023 Annual Report on Form 10-K, which is included in this report. We caution you not to place undue reliance on forward-looking statements, and we undertake no obligation to update this information, except as required by law. We urge you to carefully review and consider the disclosures made in our Form 10-K and our other filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

CHESAPEAKE'S COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on February 10, 2021 and the reinvestment of all dividends.



* APA Corporation, Coterra Energy Inc., Devon Energy Corporation, Diamondback Energy Inc., EQT Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Ovintiv Inc., Range Resources Corporation and Southwestern Energy Company

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118

chk.com