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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

OR

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

For the transition period from _____ to _____

Commission File Number 001-19514

Gulfport Energy Corporation
(Exact name of registrant as specified in its charter)

Delaware	**86-3684669**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
713 Market Drive **Oklahoma City, Oklahoma**	**73114**
(Address of principal executive offices)	(Zip Code)

(405) 252-4600
(Registrant 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, $0.0001 par value per share	GPOR	The New York Stock Exchange

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 (Section 232.405 of this chapter) during the preceding 12 months (or 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 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 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 Exchange 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 the court. Yes ☒ No ☐

The aggregate market value of our common stock held by non-affiliates on June 30, 2025 was approximately $3.1 billion. As of February 19, 2026, there were 18,558,415 shares of our $0.0001 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2026 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

GULFPORT ENERGY CORPORATION
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DEFINITIONS

Unless the context otherwise indicates, references to "us," "we," "our," "ours," "Gulfport," the "Company" and "Registrant" refer to Gulfport Energy Corporation and its consolidated subsidiaries. All monetary values, other than per unit and per share amounts, are stated in thousands of U.S. dollars unless otherwise specified. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

2026 Senior Notes. 8.00% Senior Notes due May 17, 2026.

2029 Senior Notes. 6.75% Senior Notes due September 1, 2029.

2029 Senior Notes Indenture. Indenture dated September 13, 2024 between Gulfport Operating, UMB Bank, National Association, as trustee, and the guarantors party thereto.

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bankruptcy Code. Chapter 11 of Title 11 of the United States Code.

Bankruptcy Court. The United States Bankruptcy Court for the Southern District of Texas.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent, with one barrel of NGL and crude oil being equivalent to 6,000 cubic feet of natural gas.

Board of Directors (Board). The board of directors of Gulfport Energy Corporation.

Btu. British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

Chapter 11 Cases. Voluntary petitions filed on November 13, 2020 by Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC.

CODM. Chief Operating Decision Maker.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas, oil and NGL.

Credit Facility. The Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and various lender parties, providing for a senior secured reserve-based revolving credit facility effective as of October 14, 2021, as amended most recently by the Borrowing Base Reaffirmation Agreement and Fifth Amendment to Credit Agreement dated October 30, 2025.

DD&A. Depreciation, depletion and amortization.

Debtors. Collectively, Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC.

Developed Acreage. The number of acres allocated or assignable to productive wells or wells capable of production.

Development Well. A well drilled within the proved area of a natural gas or crude oil reservoir to the depth of a stratigraphic horizon known to be productive.

Disputed Claims Reserve. Reserve used to settle any pending claims of unsecured creditors that were in dispute as of the effective date of the Plan.

Emergence Date. Gulfport filed for voluntary reorganization under Chapter 11 of the Bankruptcy Code on November 13, 2020, and subsequently operated as a debtor-in-possession, in accordance with applicable provisions of the Bankruptcy Code, until its emergence on May 17, 2021.

Exploratory Well. A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

FASB. Financial Accounting Standards Board.

GAAP. Accounting principles generally accepted in the United States of America.

Grizzly. Grizzly Oil Sands ULC.

Grizzly Holdings. Grizzly Holdings Inc.

Gross Acres or Gross Wells. Refers to the total acres or wells in which a working interest is owned.

Guarantors. All existing consolidated subsidiaries that guarantee the Company's Credit Facility or certain other debt.

Gulfport Operating. Gulfport Energy Operating Corporation.

Held By Production. Refers to an oil and gas lease continued into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

Horizontal Drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

Incentive Plan. Gulfport Energy Corporation 2021 Stock Incentive Plan, effective on the Emergence Date.

IRC. The Internal Revenue Code of 1986, as amended.

LOE. Lease operating expenses.

Marcellus. Refers to the Marcellus Play that includes the hydrocarbon bearing rock formations commonly referred to as the Marcellus formation located in the Appalachian Basin of the United States and Canada. Our acreage is located primarily in Belmont, Jefferson and Monroe County in eastern Ohio.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent, with one barrel of NGL and crude oil being equivalent to 6,000 cubic feet of natural gas.

MMBbl. One million barrels of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent, with one barrel of NGL and crude oil being equivalent to 6,000 cubic feet of natural gas.

Natural Gas Liquids (NGL). Hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

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

Net Revenue Interest (NRI). An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGL production.

NYMEX. New York Mercantile Exchange.

OCC. Oklahoma Corporation Commission.

Parent. Gulfport Energy Corporation.

Plan. The Amended Joint Chapter 11 Plan of Reorganization of Gulfport Energy Corporation and Its Debtor Subsidiaries.

Predecessor. The pre-emergence from bankruptcy organization for periods on or prior to May 17, 2021.

Productive Well. A well found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved Developed Reserves (PDP). Reserves expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. Quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved Undeveloped Reserves (PUD). Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion. 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. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

PV-10. Present net value of estimated future net revenues, discounted at 10%.

Repurchase Program. A stock repurchase program to acquire up to $1.5 billion of Gulfport's outstanding common stock. It is authorized to extend through December 31, 2026, and may be suspended from time to time, modified, extended or discontinued by the Board of Directors at any time.

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

Royalty Interest. Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

RTSR. Relative total shareholder return.

SCOOP. Refers to the South Central Oklahoma Oil Province, a term used to describe a defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko basin. The SCOOP Play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. Our acreage is primarily in Garvin, Grady and Stephens Counties.

SEC. The United States Securities and Exchange Commission.

Section 382. Internal Revenue Code Section 382.

SOFR. Secured Overnight Financing Rate.

Standardized Measure. Standardized measure of discounted future net cash flows.

Tcfe. One trillion cubic feet of natural gas equivalent, with one barrel of NGL and crude oil being equivalent to 6,000 cubic feet of natural gas.

TSR. Total shareholder return.

Undeveloped Acreage. Lease or mineral acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

USEPA. United States Environmental Protection Agency.

Utica. Refers to the Utica Play that includes the hydrocarbon bearing rock formations commonly referred to as the Utica formation located in the Appalachian Basin of the United States and Canada. Our acreage is located primarily in Belmont, Harrison, Jefferson and Monroe Counties in eastern Ohio.

Working Interest (WI). 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. Refers to West Texas Intermediate.

FORWARD-LOOKING STATEMENTS

This Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward looking statements by terms such as "may," "will," "should," "could," "would," "expects," "plans," "anticipates," "intends," "believes," "estimates," "projects," "predicts," "potential" and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future, including estimated future production and net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof and the information under the heading "2026 Outlook"), share repurchases, business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in Item 1A. "Risk Factors" and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections and elsewhere in this Form 10-K. All forward-looking statements speak only as of the date of this Form 10-K.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

We may use the Investors section of our website (www.gulfportenergy.com) to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on our website is not part of this Annual Report on Form 10-K.

SUMMARY RISK FACTORS

Financial, Liquidity and Commodity Price Risks

- Natural gas, oil and NGL prices fluctuate widely, and lower prices for extended time periods are likely to have a material adverse effect on our business.
- Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices and involve risk that our counterparties may be unable to satisfy their obligations to us.
- Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.
- Our debt and other financial commitments may limit our financial and operating flexibility.
- Our development, acquisition and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.
- Under our method of accounting for oil and natural gas properties, declines in commodity prices may result in impairment of asset value.
- A change of control could limit our use of net operating losses to reduce future taxable income.

Industry, Business and Operational Risks

- The oil and gas development, exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.
- 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.
- Part of our strategy involves using the latest available horizontal drilling and completion techniques; therefore, the results of our planned drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.
- Our undeveloped leasehold acreage must be drilled before the lease's expiration date in order to hold the lease by production. In highly competitive markets for leasehold acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.
- Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.
- Multi-well pad drilling may result in volatility in our operating results and delay the conversion of our PUD reserves.
- We are not the operator of all our oil and natural gas properties and therefore are not positioned to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.
- Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. 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.
- All of our producing properties are located in eastern Ohio and central Oklahoma, making us vulnerable to risks associated with operating in only these regions.
- The loss of one or more of the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.
- The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.
- 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.
- We are required to pay fees to some of our midstream service providers based on minimum volumes regardless of actual volume throughput.
- A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.
- Terrorist activities could materially and adversely affect our business and results of operations.

- Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.
- We may engage in acquisition and divestiture activities that involve substantial risks.

Environmental, Legal and Regulatory Risks

- We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.
- Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.
- Increased attention to sustainability matters may impact our business, financial results, or stock price.
- Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.
- Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

Risks Associated with an Investment in Us

- The market price of our securities is subject to volatility.
- Future sales or the availability for sale of substantial amounts of our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and could impair our ability to raise capital through future sales of equity securities.
- Certain of our stockholders own a significant portion of our outstanding equity securities, and their interests may not always coincide with the interests of other holders of the common stock.
- There may be future dilution of our common stock, which could adversely affect the market price of our common stock.
- Our amended and restated certificate of incorporation provides, subject to certain exceptions, that the Court of Chancery of the State of Delaware will be the sole and exclusive forum for certain stockholder litigation matters, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or stockholders.

PART I

ITEM 1. BUSINESS

Our Business

Gulfport is an independent natural gas-weighted exploration and production company with assets primarily located in the Appalachia and Anadarko basins. Our principal operations target the Utica and Marcellus formations in eastern Ohio and the SCOOP Woodford and Springer formations in central Oklahoma. Gulfport's Predecessor was incorporated in the State of Delaware in July 1997. Our corporate headquarters are located in Oklahoma City, Oklahoma and shares of Gulfport's common stock trade on the New York Stock Exchange ("NYSE") under the ticker symbol "GPOR". Our corporate strategy is focused on the economic development of our asset base in an effort to generate sustainable free cash flow.

As of December 31, 2025, we had 4.3 Tcfe of proved reserves with a Standardized Measure of $3.4 billion and a PV-10 of $3.6 billion. See "Definitions" above for our definition of PV-10 (a non-GAAP financial measure) and "Oil, Natural Gas and NGL Reserves and Estimation" below for a reconciliation of our standardized measure of discounted future net cash flows (the most directly comparable GAAP measure) to PV-10.

Information About Us

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished 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 our recent news releases. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Emergence From Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On November 13, 2020, we, and certain of our subsidiaries, filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. The Bankruptcy Court confirmed the Plan and entered the confirmation order on April 28, 2021, and the Debtors emerged from the Chapter 11 Cases on the Emergence Date. On May 18, 2021, we began trading on the NYSE under the symbol "GPOR".

Business Strategy

Gulfport aims to create sustainable value through the economic development of our significant resource plays in the Utica/Marcellus and SCOOP operating areas. Our strategy is to develop our assets in a safe, environmentally responsible manner, while generating sustainable cash flow, enhancing margins and operating efficiencies and returning capital to shareholders. To achieve these goals, we generally allocate capital to projects we believe offer the highest rate of return and we deploy leading drilling and completion techniques and technologies in our development efforts. We believe our plan to generate free cash flow on an annual basis will allow us to further strengthen our balance sheet, return capital to shareholders and increase our resource depth through incremental leasehold opportunities that provide optionality to our future development plans.

2026 Outlook

Our 2026 capital expenditure program is expected to be in a range of $400 million to $430 million, including $35 million to $40 million on maintenance land and seismic investments. In the Utica, we intend to complete drilling on approximately 18 gross (17.5 net) operated horizontal wells and commence sales on approximately 20 gross (19.5 net) operated horizontal wells. In the Marcellus, we intend to complete drilling on approximately 6 gross (5.6 net) and commence sales on approximately 4 gross (4.0 net) operated horizontal wells. In the SCOOP, we intend to complete drilling and commence sales on approximately 2 gross (1.7 net) operated horizontal wells. We expect to fund these expenditures with our operating cash flow and borrowings under our Credit Facility.

We expect this development program to result in approximately 1.030 to 1.055 Bcfe per day of production in 2026.

Additionally, in 2026, we expect to continue returning capital to shareholders through our Repurchase Program. During 2025, we repurchased 1.8 million shares for $336.3 million at a weighted average price of $188.65 per share, leaving $579.6 million remaining on our Repurchase Program, which expires on December 31, 2026.

Operating Areas

Utica/Marcellus - The Utica covers hydrocarbon-bearing rock formations located in the Appalachian Basin of the United States and Canada. We have approximately 223,000 net reservoir acres located primarily in Belmont, Harrison, Jefferson and Monroe Counties in eastern Ohio where the Utica ranges in thickness from 600 to over 750 feet.

The Marcellus covers hydrocarbon-bearing rock formations that generally overlay the Utica in Ohio. We have identified approximately 35,000 net reservoir acres of our existing leasehold for Marcellus development and have 25 PUD Marcellus locations. In 2025 we drilled, completed, and turned to sales our first four well development pad in the Marcellus. Our Marcellus development area is approximately 3,500 to 4,500 feet shallower than the Utica.

During 2025, we produced approximately 841 MMcfe per day net to our interests in Utica/Marcellus and it accounted for approximately 81% of our total production.

SCOOP - The SCOOP is a defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko Basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. We have approximately 74,000 net reservoir acres (comprised of approximately 44,000 in the Woodford formation and approximately 30,000 in the Springer formation) located primarily in Garvin, Grady and Stephens Counties. The Woodford Shale across our position ranges in thickness from 200 to over 400 feet and directly overlies the Hunton Limestone and underlies the Sycamore formation, both of which are also locally productive reservoirs. The Sycamore formation consists of hydrocarbon-bearing interbedded shales and siliceous limestones ranging in thickness from 150 to over 450 feet and is overlain by the Caney Shale. The Springer formation across our position is comprised of a series of lenticular sand and shale units. The primary targets are a series of porous, low clay and organic-rich packages within the Goddard Shale member ranging in thickness from 50 to over 250 feet.

During 2025, we produced approximately 197 MMcfe per day net to our interests in the SCOOP and it accounted for approximately 19% of our total production.

Oil, Natural Gas and NGL Reserves and Estimation

Reserve engineering is a subjective process of estimating volumes of economically recoverable oil, natural gas and NGL that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the reserve estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A. “Risk Factors” contained elsewhere in this Form 10-K.

As discussed above, the process of estimating oil, natural gas and NGL reserves is complex and requires significant judgment. As a result, we have developed internal policies and controls for estimating and recording reserves. Estimates of proved developed and undeveloped reserves and related information are presented in accordance with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules permit the use of reliable technologies to estimate and categorize reserves and require the use of the unweighted average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for the prior 12 months (unless contractual arrangements designate the price) to calculate economic producibility of reserves and the discounted cash flows reported as the Standardized Measure of Future Net Cash Flows Relating to Proved Reserves. Reliable technologies were used to support the undeveloped locations in the Utica/Marcellus and SCOOP operating areas. The Company used public and proprietary geologic and engineering data to establish continuity of the formation and its producing properties. This data included performance data, seismic data, open hole log information, petro-physical analysis of log data, mud logs, log cross-sections, gas sample analysis, statistical analysis and measurements of total organic content and thermal maturity. In our development area, these data demonstrated consistent and continuous reservoir characteristics. Refer to Note 20 of our consolidated financial statements for more information pertaining to our proved reserves and the preparation of such estimates.

Our Senior Vice President of Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with 30 years of reservoir and operations experience. In addition, our geoscience staff has approximately 58 years combined industry experience and our reservoir staff also has approximately 58 years combined experience.

During 2025, our total net natural gas, NGLs and oil proved reserves estimates attributable to the Company's interests were prepared by the Company and Netherland, Sewell & Associates, Inc. ("NSAI") conducted an audit of the proved reserves as of December 31, 2025. NSAI is an independent petroleum engineering firm and was selected for their historical experience and geographic expertise in engineering similar resources. In the course of its audit, NSAI conducted a detailed review of properties making up approximately 86% of the total proved reserves and accounting for approximately 88% of the present worth of those reserves. The estimates prepared by the Company and audited by NSAI were within the recommended 10% tolerance threshold set forth in the Standards Pertaining to the Estimation and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. A copy of the summary reserve report is included as Exhibit 99.1 to this Annual Report on Form 10-K. Our internal staff of petroleum engineers and geoscience professionals work closely with NSAI to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team members meet with NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. As needed, we provide historical information to NSAI for our properties such as ownership interest, oil and gas production, well test data, commodity prices, operating and development costs and other considerations, including availability and costs of infrastructure and status of permits.

Reserve estimates for the year ended 2024 were prepared by the Company and audited by NSAI as of December 31, 2024. Reserve estimates for the year ended 2023 were prepared by NSAI for 100% of our operating areas.

Internal Controls Over Proved Reserve Estimates

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

- review and verification of historical production, operating, marketing and capital data, which data is based on actual production as reported by us;
- verification of property ownership by our land department;
- audit of year-end reserve estimates by NSAI;
- direct reporting responsibilities by our reservoir engineering department to our Chief Executive Officer;
- review by our reservoir engineering department of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- provision of quarterly updates to our Board of Directors regarding operational data, including production, drilling and completion activity levels and any significant changes in our reserves;
- annual review by our Board of Directors of our year-end reserve report and year-over-year changes in our proved reserves;
- annual review by our senior management of adjustments to our previously adopted development plan and considerations involved in making such adjustments, including the substitution, removal or deferral of PUD locations; and
- annual review and approval by our senior management and our Board of Directors of a multi-year development plan.

The tables below set forth information as of December 31, 2025, with respect to our estimated proved developed and undeveloped oil, natural gas and NGL reserves, the associated estimated future net revenue, the PV-10 and the standardized measure. None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2025			
	Oil (MMBbl)	Natural Gas (Bcf)	NGL (MMBbl)	Total (Bcfe)
Utica & Marcellus				
Proved developed[1]	4	1,717	12	1,818
Proved undeveloped[1]	14	1,189	39	1,510
Total proved[1]	19	2,906	52	3,328
SCOOP				
Proved developed	4	440	21	587
Proved undeveloped	2	266	10	338
Total proved	5	707	31	925
Total				
Proved developed	8	2,157	33	2,404
Proved undeveloped	16	1,455	50	1,848
Total proved	24	3,612	83	4,253

Totals may not sum or recalculate due to rounding.

(1) Includes approximately 26 Bcfe and 210 Bcfe of net developed and undeveloped reserves, respectively, located in the Marcellus target formation.

	December 31, 2025		
	Proved Developed	Proved Undeveloped	Total Proved
	($ in millions)		
Estimated future net revenue[1]	$ 3,816	$ 3,145	$ 6,961
Present value of estimated future net revenue (PV-10)[1]	$ 2,291	$ 1,331	$ 3,622
Standardized measure[1]			3,403

Totals may not sum due to rounding.

(1) 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 prices and costs under existing economic conditions as of December 31, 2025, 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, 2025. The prices used in our PV-10 measure were the average WTI Spot price of $66.01 per barrel and the average Henry Hub Spot price of $3.39 per MMBtu, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2025. 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 $219 million as of December 31, 2025.

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 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 reconciliation 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 oil and gas reserves.

The following table summarizes the changes in our estimated proved reserves during 2025 (in Bcfe):

Proved Reserves, December 31, 2024	3,969
Sales of oil and natural gas reserves in place	—
Extensions and discoveries	701
Revisions of prior reserve estimates	(38)
Current production	(379)
Proved Reserves, December 31, 2025	4,253

Total may not sum due to rounding.

Extensions and discoveries. These are additions to our proved reserves that result from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery. Extensions of approximately 701 Bcfe of proved reserves were primarily attributable to the continued development of our Utica/Marcellus and SCOOP acreage. We added 35 PUD locations in the Utica/Marcellus which included 28 Utica locations for 382 Bcfe and 7 Marcellus locations for 62 Bcfe. We also added 11 operated locations in the Utica to PDP which were not previously booked for 119 Bcfe. In the SCOOP, we added 6 PUD locations for 138 Bcfe.

Revisions of prior reserve estimates. Revisions represent changes in previous reserve estimates, either upward or downward, resulting from development plan changes, new information normally obtained from development drilling and production history or a change in economic factors, such as commodity prices, operating costs or development costs.

We experienced total downward revisions of 38 Bcfe in estimated proved reserves. These consisted of upward revisions of 255 Bcfe which were associated with commodity price changes. Commodity prices experienced volatility throughout 2025 and the 12-month unweighted average of the first-day-of-the-month price for natural gas increased from $2.13 per MMBtu for 2024 to $3.39 per MMBtu for 2025, the 12-month average WTI spot price for crude oil decreased from $76.32 per barrel for 2024 to $66.01 per barrel for 2025, and the calculated average weighted price for NGL over the remaining lives of the properties decreased from $31.30 per barrel for 2024 to $30.17 per barrel for 2025. Additionally, there were upward revisions of 161 Bcfe due to an increase in working interest and net revenue interest as a result of our successful leasing efforts throughout 2025. These were offset by downward revisions of 185 Bcfe and 129 Bcfe as a result of development schedule changes and PUD well design changes, respectively. The schedule changes moved the development of 9 Utica PUD locations and 4 SCOOP PUD locations beyond the SEC requirement of development within five years from initial booking and while these locations are excluded from our SEC reserves report, they remain in our longer-term development plan. Design changes primarily include well spacing and lateral length updates with a portion of these volumes now to be developed with locations outside of the SEC designated five-year development time frame. These development schedule and design changes reflect our ongoing commitment to optimizing the long-term plan to best develop our assets and maximize cash flow and overall economic returns. Finally, downward revisions of 141 Bcfe were a result of a combination of various economic assumptions and well performance updates.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves at December 31, 2025, 2024 and 2023, and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 20 of our consolidated financial statements.

Proved Undeveloped Reserves

As of December 31, 2025, our PUDs totaled 1,455 Bcf of natural gas, 16 MMBbl of oil and 50 MMBbl of NGL, for a total of 1,848 Bcfe. Approximately 82% and 18% of our PUD reserves at year-end 2025 were located in Utica/Marcellus and SCOOP, respectively. Our PUDs will be converted from undeveloped to developed as the applicable wells commence production or when there are no material incremental completion capital expenditures associated with such proved developed reserves.

We record PUD locations only after a development plan has been approved by our senior management and Board of Directors to complete the associated development drilling within five years from the time of initial booking. The PUD locations identified in our development plan are determined based on an analysis of the information that we have available at that time. After a development plan has been adopted, we may periodically make adjustments to the approved development plan due to events and circumstances that have occurred subsequent to the time the plan was approved. These circumstances may include changes in commodity price outlook and costs, delays in the availability of infrastructure, well permitting delays and new data from recently completed wells.

The following table summarizes the changes in our estimated proved undeveloped reserves during 2025 (in Bcfe):

Proved Undeveloped Reserves, December 31, 2024	1,861
Sales of oil and natural gas reserves in place	—
Extensions and discoveries	582
Conversion to proved developed reserves	(417)
Revisions of prior reserve estimates	(177)
Proved Undeveloped Reserves, December 31, 2025	1,848

Total may not sum due to rounding.

Extensions and discoveries. Our extensions of approximately 582 Bcfe were primarily attributed to the addition of 41 PUD locations as a result of our current five-year development plan that is focused on generating sustainable cash flow. These additions included 35 PUD locations in the Utica/Marcellus and 6 PUD locations in the SCOOP.

Conversion to proved developed reserves. Our 2025 development activities resulted in the conversion of approximately 417 Bcfe into proved developed producing reserves, attributable to 31 PUD locations in the Utica/Marcellus and 11 PUD locations in the SCOOP. These 42 PUDs represent a conversion rate of 28% for 2025.

Revision of prior reserve estimates. We experienced total downward revisions of 177 Bcfe in estimated proved undeveloped reserves. This included 182 Bcfe and 84 Bcfe of downward revisions associated with changes in our development schedule changes and PUD well design changes, respectively. The schedule changes moved the development of 9 Utica PUD locations and 4 SCOOP PUD locations beyond the SEC requirement of development within five years from initial booking and while these locations are excluded from our SEC reserves report, they remain in our longer-term development plan. Design changes primarily include well spacing and lateral length updates with a portion of these volumes now to be developed with locations outside of the SEC designated five-year development time frame. These development schedule and design changes reflect our ongoing commitment to optimizing the long-term plan to best develop our assets and maximize cash flow and overall economic returns. These downward revisions were offset by upward revisions of 89 Bcfe in estimated proved reserves from a combination of changes including working interest and net revenue interest, well forecasts and price changes.

Costs incurred relating to the development of PUDs were approximately $235.9 million in 2025.

All PUD locations included in our 2025 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2025, 1.77% of our total proved reserves were classified as proved developed non-producing.

PV-10 Sensitivities

As noted above, our proved reserves at December 31, 2025, were calculated using prices based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for 2025 of $66.01 per barrel and $3.39 per MMBtu. Holding production and development costs constant, if SEC pricing were $72.61 per barrel and $3.73 per MMBtu, or a 10% increase, this would have resulted in an increase of 38 Bcfe of our total proved reserves and a $0.77 billion increase in PV-10 value at December 31, 2025. Holding production and development costs constant, if SEC pricing were $59.41 per barrel and $3.05 per MMBtu, or a 10% decrease, this would have resulted in a decrease of 54 Bcfe of our total proved reserves and a $0.77 billion decrease in PV-10 value at December 31, 2025. For the low price scenario 132 PUDs were PV-10 economic.

Acreage

The following table presents our total gross and net developed and undeveloped acres as of December 31, 2025:

	Developed Acreage		Undeveloped Acreage	
Field	Gross	Net	Gross	Net
Utica & Marcellus	170,209	142,239	83,069	80,294
SCOOP	50,735	36,174	10,689	7,680
Total	220,944	178,413	93,758	87,974

Of our leases that are not held by production or held by other applicable lease provisions, most have a five-year primary term, and many include an optional right to extend the primary term for an additional three or five years. We manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our operations to establish production in paying quantities in order to hold leases prior to the expiration dates, paying the prescribed lease extension payments, planning non-core divestitures or strategic acreage trades with other operators to high-grade our lease inventory and voluntarily allowing certain leases to expire that are no longer part of our development plans. The following table sets forth the potential expiration periods of gross and net undeveloped leasehold acres as of December 31, 2025:

	Undeveloped Acres	
	Gross Acres	Net Acres
2026	2,827	2,806
2027	1,672	1,636
2028	10,048	10,042
After 2028	19,930	19,930
Held by production	59,281	53,560
Total	93,758	87,974

Productive Wells

The following table presents our total gross and net productive wells, expressed separately for oil and gas, as of December 31, 2025:

	NRI/WI	Productive Oil Wells		Productive Gas Wells		Total Wells	
Field	Percentages	Gross	Net	Gross	Net	Gross	Net
Utica & Marcellus	50.25/61.58	69	25.5	697	446.2	766	471.7
SCOOP	20.86/25.82	129	13.3	518	153.8	647	167.1
Total[1]		215	38.8	1,380	600.0	1,595	638.8

(1) We also have override/royalty interests in 182 wells with an average NRI of 0.6%, which are not material to our operations. Totals may not sum due to rounding.

Drilling Activity

The following table sets forth information with respect to operated wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	29	28.7	21	19.8	24	21.9
Dry	—	—	—	—	—	—
Total	29	28.7	21	19.8	24	21.9
Exploratory:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	—	—	—	—	—	—

The following table presents activity by operating area for the year ended December 31, 2025:

	Operated				Non-Operated			
	Drilled		Turned to Sales		Drilled		Turned to Sales	
Field	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Utica & Marcellus[1]	27.0	26.9	30.0	30.0	8.0	0.1	14.0	0.0
SCOOP[2]	2.0	1.8	2.0	1.8	18.0	0.1	23.0	0.2
Total	29.0	28.7	32.0	31.8	26.0	0.2	37.0	0.2

(1) Of the 27 gross operated wells drilled in 2025, 22 were completed as producing wells and five were in various stages of drilling and completion as of December 31, 2025.
(2) The two gross operated wells that were drilled in 2025 were completed as producing wells as of December 31, 2025.

Production, Prices and Production Costs

The following table presents our production volumes, average prices received and average production costs during the periods indicated (sales totals in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Natural gas sales			
Natural gas production volumes (MMcf)	338,296	354,154	350,306
Natural gas production volumes (MMcf) per day	927	968	960
Total sales	$ 1,056,429	$ 714,160	$ 831,812
Average price without the impact of derivatives ($/Mcf)	$ 3.12	$ 2.02	$ 2.37
Impact from settled derivatives ($/Mcf)	$ 0.14	$ 0.80	$ 0.42
Average price, including settled derivatives ($/Mcf)	$ 3.26	$ 2.82	$ 2.79
Oil and condensate sales			
Oil and condensate production volumes (MBbl)	2,260	1,459	1,363
Oil and condensate production volumes (MBbl) per day	6	4	4
Total sales	$ 133,644	$ 101,589	$ 99,854
Average price without the impact of derivatives ($/Bbl)	$ 59.12	$ 69.64	$ 73.27
Impact from settled derivatives ($/Bbl)	$ 4.04	$ 0.11	$ (2.53)
Average price, including settled derivatives ($/Bbl)	$ 63.16	$ 69.75	$ 70.74
NGL sales			
NGL production volumes (MBbl)	4,554	3,818	4,386
NGL production volumes (MBbl) per day	12	10	12
Total sales	$ 133,454	$ 112,855	$ 119,717
Average price without the impact of derivatives ($/Bbl)	$ 29.30	$ 29.56	$ 27.29
Impact from settled derivatives ($/Bbl)	$ (0.07)	$ (0.56)	$ 2.07
Average price, including settled derivatives ($/Bbl)	$ 29.23	$ 29.00	$ 29.36
Natural gas, oil and condensate and NGL sales			
Natural gas equivalents (MMcfe)	379,182	385,814	384,802
Natural gas equivalents (MMcfe) per day	1,039	1,054	1,054
Total sales	$ 1,323,527	$ 928,604	$ 1,051,383
Average price without the impact of derivatives ($/Mcfe)	$ 3.49	$ 2.41	$ 2.73
Impact from settled derivatives ($/Mcfe)	$ 0.15	$ 0.73	$ 0.40
Average price, including settled derivatives ($/Mcfe)	$ 3.64	$ 3.14	$ 3.13
Production Costs:			
Average lease operating expenses ($/Mcfe)	$ 0.22	$ 0.18	$ 0.18
Average taxes other than income ($/Mcfe)	0.08	0.08	0.09
Average transportation, gathering, processing and compression ($/Mcfe)	0.95	0.91	0.91
Total lease operating expenses, midstream costs and taxes other than income ($/Mcfe)	$ 1.25	$ 1.17	$ 1.17

Totals may not sum or recalculate due to rounding.

The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2025:

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Utica & Marcellus			
Net Production			
Natural gas (MMcf)	283,667	296,548	279,428
Oil (MBbl)	1,729	847	255
NGL (MBbl)	2,183	1,072	856
Total (MMcfe)	307,137	308,060	286,095
Average price without the impact of derivatives:			
Natural gas ($/Mcf)	$ 3.11	$ 1.99	$ 2.34
Oil ($/Bbl)	$ 58.06	$ 66.84	$ 70.18
NGL ($/Bbl)	$ 34.87	$ 37.01	$ 33.63
Production Costs:			
Average lease operating expenses ($/Mcfe)	$ 0.20	$ 0.16	$ 0.16
Average taxes other than income ($/Mcfe)	0.05	0.06	0.05
Average transportation, gathering, processing and compression ($/Mcfe)	0.96	0.93	0.97
Total lease operating expenses, midstream costs and taxes other than income ($/Mcfe)	$ 1.21	$ 1.15	$ 1.18
SCOOP			
Net Production			
Natural gas (MMcf)	54,629	57,605	70,878
Oil (MBbl)	531	612	1,108
NGL (MBbl)	2,371	2,746	3,530
Total (MMcfe)	72,045	77,753	98,707
Average price without the impact of derivatives:			
Natural gas ($/Mcf)	$ 3.19	$ 2.13	$ 2.53
Oil ($/Bbl)	$ 62.59	$ 73.51	$ 73.98
NGL ($/Bbl)	$ 24.18	$ 26.65	$ 25.76
Production Costs:			
Average lease operating expenses ($/Mcfe)	$ 0.31	$ 0.28	$ 0.25
Average taxes other than income ($/Mcfe)	0.17	0.13	0.17
Average transportation, gathering, processing and compression ($/Mcfe)	0.88	0.83	0.73
Total lease operating expenses, midstream costs and taxes other than income ($/Mcfe)	$ 1.36	$ 1.24	$ 1.15

Our Investments

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.5% interest in Grizzly. As of December 31, 2025, Grizzly had approximately 639,000 net acres under lease in the Athabasca, Peace River, and Cold Lake regions of Alberta, Canada. Grizzly's operations have been suspended since 2015. Additionally, Grizzly had no proved reserves as of December 31, 2025. We elected to cease funding capital calls in 2019, and we have no obligation to fund any future projects Grizzly may consider pursuing. Failure to fund capital calls will lead to continued dilution of our equity ownership interest in Grizzly.

Marketing

The principal function of our marketing operations is to provide natural gas, oil and NGL marketing services, including securing and negotiating commodity transactions, gathering, hauling, processing and transportation services, contract administration and nomination services for production from Gulfport-marketed wells. Generally, natural gas and NGL production is sold to purchasers under both spot and term transactions. Oil production is sold under both spot and term transactions with the majority of our sales contracts being shorter term in nature.

We have entered into long-term gathering, processing and transportation contracts with various parties that reserve capacity for fixed, determinable quantities of production over specified periods of time. Some contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. In addition, we periodically enter into a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including risk mitigation and satisfaction of our firm transportation delivery commitments. These marketing activities often enhance the value of our production by aggregating volumes and allowing improved flexibility in relation to deal structure, size and counterparty exposure whether through intermediary markets or direct end markets. See Note 17 of our consolidated financial statements for further discussion of our commitments.

Major Customers

Our total natural gas, oil and NGL sales, before the effects of hedging, to major customers (purchasers in excess of 10% of total natural gas, oil and NGL sales) for the years ended December 31, 2025, 2024 and 2023 were as follows:

	% of Sales
Year Ended December 31, 2025	
Customer A	14 %
Year Ended December 31, 2024	
Customer A	15 %
Year Ended December 31, 2023	
Customer A	12 %

Competition

The oil and natural gas industry is intensely competitive, and we compete with many other companies that have greater resources than we have. Competition can negatively impact our ability to successfully source quality vendors, service providers, employees and contractors to secure optimal pipeline access and end markets in which to sell our production, to acquire new properties, and our search for, and the development of, reserves. Many of our competitors not only explore for and produce oil and natural gas, but also have midstream and further downstream operations and market a variety of hydrocarbon products on a regional, national or worldwide basis. In addition, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include renewable sources such as wind or solar energy in addition to coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonality

Gulfport drills and completes wells throughout the year, but adverse weather conditions can impact drilling, completion, and field operations, as well as third-party midstream and downstream pipeline operations, which can impact overall production volumes. Seasonal anomalies can minimize or exaggerate the impact on these operations, while extreme weather events can materially constrain our operations for short periods of time.

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a preliminary review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations at the time we are preparing to develop the undeveloped leases and when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to certain imperfections in title, encumbrances, easements, servitudes or other restrictions, none of which, in management's opinion, will in the aggregate materially restrict our operations.

Regulation - Environment, Health and Safety

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 and 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 completing wells;
- hydraulic fracturing;
- water withdrawal;
- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- air emissions and fluid discharges;
- climate change;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas 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.

Federal, state and local governments have periodically taken steps to reduce emissions of greenhouse gases (“GHG”). We consider the costs of environmental, safety and health protection and compliance to be necessary, manageable parts of our business. 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 policy and regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to compliance with the protection of the environment, safety and health have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters. See the “Risk Factors” described in Item 1A of this report for further discussion of governmental regulation and ongoing regulatory changes, including with respect to environmental matters.

Our operations are also 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 oil and gas wells, and the unitization or pooling of oil and gas properties. In the United States, some states allow the compulsory pooling or integration of tracts to facilitate exploration and development. Other states rely on voluntary pooling of lands and leases which may make it more difficult to develop oil and gas 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 often impose additional operational costs to us and can also limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

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 reduce the amount of natural gas, oil and NGL that we are ultimately able to produce in commercial quantities 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 Bureau of Land Management ("BLM") or Bureau of Indian Affairs ("BIA") of the 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 been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. If future developments result in additional restrictions on drilling, limitations on the availability of leases, or restrictions on the ability to obtain required permits, it could have a material adverse impact on our operations. Permitting activities on federal lands 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.

Operating Hazards and Insurance

The oil and natural gas 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 minimum limit of $25 million for single well limits and $37.5 million limit for multi-well pads. This policy 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 $51 million comprehensive general liability and umbrella insurance program. In addition, we maintain a $10 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, as well as auto liability for our company vehicles. 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.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities in response to federal and state requirements. The plans go through a technical review every five years and are updated as necessary. As required by applicable regulations, our facilities are built with secondary containment systems to capture potential releases. We also own additional spill kits with oil booms and absorbent pads that are readily available, if needed. In addition, we have emergency response companies on retainer. These companies specialize in the clean-up of hydrocarbons as a result of spills, blow-outs and natural disasters, and are on call to us 24 hours a day, seven days a week when their services are needed. We pay these companies a retainer plus additional amounts when they provide us with clean up services. Our aggregate payments for the retainer and clean-up services during each of 2025, 2024 and 2023 were immaterial. While these companies have been able to meet our service needs when required from time to time in the past, it is possible that the ability of one or more of them to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the areas in which we operate and the nature of our production, we believe other companies would be available to us in the event our primary remediation companies are unable to perform.

Human Capital Management

Employees

As of December 31, 2025, we had 245 employees, an increase of approximately 5% from the 235 employees as of December 31, 2024. All of our employees are non-bargaining.

The attraction and retention of qualified employees continues to be one of our highest priorities. We focus on making substantive improvements to key areas that impact our employees. During 2025, we continued making significant investments in our talent management and retention processes, including increasing funds allocated to annual salary increases, short-term incentive payments, long-term incentive equity awards, 401(k) matches for eligible employees, and other enhancements to our benefits offerings. We remain committed to providing fair and competitive compensation programs and adequate development and advancement opportunities to our employees. We believe these practices serve as talent acquisition and retention tools, as our employees' continued engagement and commitment to the Company is critical to our success.

Over the course of 2025, Gulfport continued to develop and revise Company policies, including those intended to implement our Business Code of Conduct and Ethics, which provides a framework for how we interact with our employees, vendors and other stakeholders when conducting our operations. To that end, we provided all of our employees with annual trainings focused on the guidelines, rules, and principles that must be followed when acting on the Company's behalf. We remain committed to maintaining the highest standards of business ethics.

Health, Safety & Environment

Safety is at the forefront of everything we do. We have a robust annual training program, including environmental, health, and safety topics. Our safety program, WORK SAFE, is comprised of twelve key topics including critical tasks and cultural conditions. We hold regular safety briefings to discuss daily operations and routinely have safety stand-down meetings highlighting potential risks. Every employee is empowered to use their stop-work authority to cease operating if work is being performed in an unsafe manner. We monitor employee safety by establishing annual company-wide key safety metrics tied to leading indicators (i.e., incident reporting and investigations, hazard observations, safety and health meetings) and lagging indicators (i.e., injury rates and preventable motor vehicle accidents).

As part of our focus on continuous improvement, we monitor and communicate key environmental and safety metrics both internally and externally. Trend analysis guides us to make operational changes and policy updates as necessary to protect our employees, the public and the environment. We establish and carefully track key environmental and safety metrics that are a component of every employee’s incentive compensation opportunity annually.

We have established several programs to ensure that our employees and external partners are appropriately trained to perform the critical work we do safely and effectively. We continued to reinforce our WORK SAFE program and provided training to leaders on reinforcement strategies. Additionally, we continued the WORK GREEN program, which focuses on protecting the air, land and water where we operate and includes community-based volunteer events targeting environmental clean-up and habitat improvement initiatives. An environmental training on the elements of WORK GREEN was created and delivered to all employees.

Training & Development

Gulfport invests in our employees' professional growth to build strong teams and develop leaders for today and the future. We build our dynamic team of industry-leading professionals by engaging them in interesting and rewarding work and providing training and development opportunities. We utilize training sessions with content developed by experts in the safety, legal, information security and regulatory compliance fields, and we offer a blend of training sessions through both computer-based modules and live, instructor-led sessions. We believe our training efforts support a compliant safety-first mindset in everything we do. We continue to provide professional and workplace-related training resources to employees through universities, electronic content services and specialized courses related to our industry through our tuition reimbursement program or third-party providers.

Executive Officers

John Reinhart, President, Chief Executive Officer and Director

On January 18, 2023, the Board of Directors appointed Mr. Reinhart, 57, as President, Chief Executive Officer and Director, effective as of January 24, 2023. Mr. Reinhart joined the Company with over two decades of oil and gas industry leadership experience. Most recently, he served as President, Chief Executive Officer and member of the board of directors of Montage Resources Corporation where he led actions that positioned Montage as an attractive strategic partner with sufficient scale, low debt profile and achievement of top-quartile operational and financial metrics. Mr. Reinhart previously served as President, Chief Executive Officer and member of the board of directors of Blue Ridge Mountain Resources and as Chief Operating Officer at Ascent Resources. He started his oil and gas career at Schlumberger before joining Chesapeake Energy Corporation, where he held operations roles with increasing responsibility. Mr. Reinhart began his career in the United States Army, serving tours in Panama and Iraq. Mr. Reinhart graduated from West Virginia University with a Bachelor of Science degree in Mechanical Engineering.

Michael Hodges, Executive Vice President and Chief Financial Officer

On April 3, 2023, the Board of Directors appointed Mr. Hodges, 47, as Executive Vice President and Chief Financial Officer. Most recently, Mr. Hodges served as Senior Vice President, Finance and Accounting at Leon Capital Group. Prior to joining Leon Capital, he was the Executive Vice President and Chief Financial Officer for Montage Resources Corporation until its merger with Southwestern Energy Company in November 2020. From 2012 until joining Montage Resources in 2018, Mr. Hodges served as the Chief Financial Officer for three upstream energy companies focused on near-term value creation through the acquisition and early-stage development of oil and natural gas resources. Mr. Hodges received his Bachelor of Business Administration in Finance from the University of Oklahoma and a Master of Science in Energy Management from Oklahoma City University and is a Certified Public Accountant in the State of Oklahoma.

Patrick Craine, Executive Vice President and Chief Legal and Administrative Officer

Mr. Craine, 53, has served as Chief Legal and Administrative Officer since June 2021 and joined Gulfport as Executive Vice President, General Counsel and Corporate Secretary in May 2019. Prior to joining the Company, Mr. Craine served as Deputy General Counsel – Chief Risk and Compliance Officer at Chesapeake Energy Corporation. Prior to joining Chesapeake in 2013, Mr. Craine was a partner with Bracewell LLP, a global law firm, where his practice focused on securities and corporate regulatory matters and investigations. Before Mr. Craine entered private practice, he served as a lawyer with the U.S. Securities and Exchange Commission and the Financial Industry Regulatory Authority where he held leadership positions in their Oil and Gas Task Forces. Mr. Craine has over 25 years of extensive senior-level experience handling a broad range of securities, corporate, regulatory, governance, compliance and litigation matters, with particular expertise in the energy industry. Mr. Craine received his Bachelor of Arts degree, summa cum laude, Phi Beta Kappa, from Wabash College, and his Juris Doctorate, cum laude, from the Southern Methodist University Dedman School of Law.

Matthew Rucker, Executive Vice President and Chief Operating Officer

Mr. Rucker, 40, joined Gulfport as the Senior Vice President of Operations in March 2023. On February 24, 2025, Matthew Rucker was promoted to Executive Vice President and Chief Operating Officer. He joined Gulfport from Javelin Energy Partners where he previously served as Vice President of Production Operations starting in August 2022. Mr. Rucker joined Javelin in July 2022 as the Vice President of Business Development. Prior to joining Javelin, Mr. Rucker served as the Executive Vice President, Chief Operating Officer for Montage Resources Corporation following Montage's successful business combination transaction with Blue Ridge Mountain Resources in June 2020. Prior to Montage, Mr. Rucker served as Vice President, Resource Planning and Development of Blue Ridge from 2016 to 2020. Prior to joining Blue Ridge, Mr. Rucker served as a Production Superintendent for Chesapeake Energy Corporation from January 2014 to October 2016, overseeing Chesapeake's Utica Shale production. As a member of Chesapeake's Eastern Division leadership team, Mr. Rucker focused on the safe and efficient optimization of production in the Utica Shale and led an operating team of over 45 employees. During his service at Chesapeake, Mr. Rucker held several engineering positions in the Marcellus and Utica Shale asset teams within reservoir, primarily focused on strategic joint ventures, divestitures, acquisitions and resource development planning. Mr. Rucker received his Bachelor of Science degree in Petroleum Engineering from Marietta College and a Master of Business Administration in Energy from Texas Christian University. He serves on the Marietta College Industry Advisory Council and is a member of the Society of Petroleum Engineers.

Michael Sluiter, Senior Vice President of Reservoir Engineering

Mr. Sluiter, 53, joined Gulfport in December 2018 from Noble Energy, Inc., where he held various engineering and leadership positions from March 2007 to November 2018, including Permian Basin Business Unit Manager, Appalachian Reservoir Engineering Supervisor, and Business Development Engineering Advisor. Prior to joining Noble Energy, Mr. Sluiter worked for Santos Ltd., at the Australian headquarters in Adelaide and in Houston, primarily focused on petroleum engineering and planning functions Mr. Sluiter began his career as a wireline field services engineer for Schlumberger, Inc. and holds a Bachelor of Science degree in Chemical Engineering from the University of Sydney, Australia.

Lester Zitkus, Senior Vice President of Land

Mr. Zitkus, 60, has served as Senior Vice President of Land since January 2017 and joined the Company as Vice President of Land in March 2014. Prior to joining the Company, Mr. Zitkus served as an independent consultant from October 2013 to March 2014 and as Vice President of Land for Chesapeake Energy Corporation from May 2007 to October 2013. During his 20-year tenure with Equitable Resources Inc. (now EQT Corp.), he held various positions, including Vice President of Operations and Senior Vice President of Land, between 1987 and 2007. He holds a degree in Mineral Land Management from the University of Evansville. Mr. Zitkus is a member of the American Association of Professional Landmen and Past Regional Director of the Independent Petroleum Association of America.

There are no family relationships among our executive officers or between any executive officer and any member of the Board of Directors. Each executive officer serves at the discretion of the Board of Directors.

ITEM 1A. RISK FACTORS

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a summary of significant factors 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, operating results, cash flows, reserves 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.

Financial, Liquidity and Commodity Price Risks

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, cash flows, profitability, future rate of growth, production and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for natural gas and, to a lesser extent, oil and NGL. 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, oil and NGL prices may result in ceiling test write-downs of our oil and natural gas properties.

Historically, the markets for natural gas, oil and NGL have been volatile, and they are likely to continue to be volatile. For example, during 2024, WTI prices ranged from $66.73 to $87.69 per barrel and the Henry Hub spot market price of natural gas ranged from $1.21 to $13.20 per MMBtu. During 2025, WTI prices ranged from $55.44 to $80.73 per barrel and the Henry Hub spot market price of natural gas ranged from $2.65 to $9.86 per MMBtu.

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

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- the level of prices, and expectations about future prices, of oil and natural gas;
- changes in the level of consumer and industrial demand, including impacts from global or national health epidemics and concerns;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- the price and availability of alternative fuels;
- technological advances and changing consumer attitudes affecting energy consumption;
- risks associated with operating drilling rigs;
- 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 oil, natural gas, liquefied natural gas and NGL;
- the price and level of foreign imports and exports, including as a result of U.S. trade policy;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries and others to agree to and maintain oil price and production controls;
- political or economic instability or armed conflict in oil and natural gas producing regions;
- weather conditions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. Even with natural gas, oil and NGL derivatives currently in place to mitigate price risks associated with a portion of our future cash flows, we have substantial exposure to natural gas prices, and to a lesser extent, oil and NGL prices, in 2026 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that we may economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties.

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 the pricing environment for certain time periods is not deemed to be favorable. 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.

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 its 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.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

Our earnings are exposed to interest rate risk associated with borrowings under our Credit Facility, which is structured under floating rate terms. As such, our interest expense is sensitive to fluctuations in the SOFR benchmark. For the year ended December 31, 2025, amounts borrowed under our Credit Facility bore interest at the weighted average rate of 6.53%. A 1% increase in the average interest rate would increase our interest expense by approximately $1.5 million based on outstanding borrowings under our Credit Facility at December 31, 2025. An increase in our interest rate at the time we have variable interest rate borrowings outstanding under our Credit Facility will increase our costs, which may have a material adverse effect on our results of operations and financial condition. As of December 31, 2025, we did not hedge our interest rate risk.

Our debt and other financial commitments may limit our financial and operating flexibility.

Our total principal debt was approximately $797.0 million at December 31, 2025. We also had various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services, products and properties. Our financial commitments could have important consequences to our business, including, but not limited to, limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, to pay dividends, to repurchase shares of our common stock, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flows from operations to make payments on our debt or to comply with restrictive terms of our debt. Higher levels of debt may make us more vulnerable to general adverse economic and industry conditions. Additionally, the agreement governing our credit facility and the indentures governing our senior notes contain a number of covenants that impose constraints on us, including requirements to comply with certain financial covenants and restrictions on our ability to dispose of assets, make certain investments, incur liens and additional debt, and engage in consolidations, mergers and acquisitions. A downgrade in our credit rating could significantly increase our collateral requirements for commercial contracts and derivatives and restrict or limit our access to trade credit or capital. If commodity prices decline and we reduce our level of capital spending and production declines or we incur additional impairment expense or the value of our proved reserves declines, we may not be able to incur additional indebtedness, may need to repay outstanding indebtedness and may not be in compliance with the financial covenants in our debt instruments in the future. Refer to “Management's Discussion and Analysis of Financial Condition and Results of Operations” in Part II, Item 7 of this Annual Report on Form 10-K and Note 4 of our consolidated financial statements for more information regarding the financial covenants and our Credit Facility.

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

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We have made and expect to make in the future substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves.

Historically, we have financed capital expenditures primarily with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- our ability to acquire, locate and produce economically new reserves; and
- our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital through a variety of means. We cannot guarantee that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

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

Under our method of accounting for oil and natural gas properties, declines in commodity prices may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proved oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting oil and NGL barrels to gas equivalents at the ratio of one barrel to six Mcf of gas.

Under the full cost method of accounting for oil and gas properties, we are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or non-cash write-down is required. A ceiling test impairment can result in a significant loss for a particular period. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase. Future non-cash asset impairments could negatively affect our results of operations.

A change of control could limit our use of net operating losses to reduce future taxable income.

As of December 31, 2025, we had a net operating loss, or NOL, carryforward of approximately $1.5 billion for federal income tax purposes. If we were to experience an "ownership change," as determined under IRC Section 382, our ability to offset taxable income arising after the ownership change with NOLs generated prior to the ownership change would be limited, possibly substantially. In general, an ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate for the month in which such ownership change occurs. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

Industry, Business and Operational Risks

The oil and gas development, exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.

We face competition in every aspect of our business, including 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 and may have greater access to the capital and credit markets. Many of these companies not only explore for and produce oil and natural gas but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. As a result, these competitors may be able to address these competitive factors 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.

In addition, the oil and gas industry is characterized by rapid technological change and the introduction of new products and services. Competitors that develop or adopt new technologies more quickly may gain a significant advantage, which could require us to incur substantial costs to remain competitive. Some industry participants have greater financial, technical, and personnel resources, enabling them to implement innovations sooner and more effectively than we can. Our ability to respond to these changes in a timely and cost efficient manner is uncertain, and if technologies we rely on become obsolete, our business, financial condition, or results of operations could be materially and adversely affected.

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.

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 oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2025, approximately 43% of our total estimated proved reserves were PUDs and may not be ultimately developed or produced. Recovery of PUDs requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports audited by an independent petroleum engineering firm assume that substantial capital expenditures are required to develop such reserves. Estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not be as estimated. Delays in the development of our reserves, further decreases in commodity prices or increases in costs to drill and develop such reserves will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. 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, 2025 present value is based on a $3.39 per MMBtu of gas price and a $66.01 per Bbl of oil price, before considering 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.

Actual future net revenues from our oil and natural gas properties will also be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of future net cash flows from our proved reserves and their present value. 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 oil and gas 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. Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We acquire unproven 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 oil and natural gas 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, 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. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale formations. All costs of development and exploratory drilling activities are capitalized under the full cost method, even if the activities do not result in commercially productive discoveries, which may result in a future impairment of our oil and natural gas properties if commodity prices decrease.

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 oil or natural gas 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.

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

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the development activities we employ, such as offset drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of offset drilling, adjacent wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing.

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

Our undeveloped leasehold acreage must be drilled before the lease's expiration date in order to hold the lease by production. In highly competitive markets for leasehold acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless a lease contains an optional right to extend its term or, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Although approximately 84% of our Utica/Marcellus acreage is held by existing production, the remaining acreage is subject to expiration. Of the remaining 16% of our Utica/Marcellus acreage not held by production, approximately 7% will be subject to expiration in 2026, 4% in 2027, 28% in 2028 and approximately 61% thereafter, although a portion of our Utica/Marcellus leases generally grant us the right to extend the term for an additional three or five-year period. Approximately 99% of our SCOOP acreage is held by existing production; the remaining acreage is subject to expiration. Although we seek to actively manage our undeveloped leasehold properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas 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 certain leases. The cost to renew expiring leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. If we are unable to fund the cost of renewing expiring leases, portions of our leasehold acreage could expire and our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our oil and gas 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;
- loss of drilling fluid circulation;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control, as well as the mishandling or underground migration of fluids and chemicals;
- risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground

migration of fracturing fluids, including chemical additives;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures, which may be exacerbated by climate change;
- 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, including liabilities for environmental damage caused by previous owners of properties purchased by us;
- 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 opinions.

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.

While 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, cybersecurity breaches, 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 uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Multi-well pad drilling may result in volatility in our operating results and delay the conversion of our PUD reserves.

We utilize multi-well pad drilling where practical. Wells drilled on a pad are not turned to sales until all wells on the pad are drilled and cased and the drilling rig is moved from the location. In addition, existing wells that offset newly drilled wells may be temporarily shut in during the drilling and completion process. As a result, multi-well pad drilling delays the completion of wells and the commencement of production from new wells and may negatively affect the production from existing offset wells, all of which may cause volatility in our operating results from period to period. Finally, delays in completion of wells may impact planned conversion of PUD reserves to PDP reserves.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

We are not the operator of all of the properties in which we have an interest and have limited ability to exercise influence over the operations of such non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploration activities on properties operated by others will depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. 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.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. For water sourcing, we first seek to use non-potable water supplies for our operational needs. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must then be obtained from other sources and transported to the drilling site. An 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 new environmental regulations could further restrict our ability to conduct operations such as hydraulic fracturing by restricting the disposal of things such as produced water and drilling fluids.

All of our producing properties are located in eastern Ohio and central Oklahoma, making us vulnerable to risks associated with operating in only these regions.

Our largest fields by production are located in eastern Ohio and central Oklahoma. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production in these geographic regions caused by weather conditions such as snow, ice, fog, rain, hurricanes, tornados or other natural disasters or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We may not be able to obtain and maintain adequate insurance at rates we consider reasonable and it is possible that certain types of coverage may not be available.

The loss of one or more of the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.

The largest purchaser of our oil and natural gas during the year ended December 31, 2025, accounted for approximately 14% of our total natural gas, oil and NGL revenues. If this purchaser or one or more other significant purchasers, is unable to satisfy its contractual obligations, we may be unable to sell such production to other customers on terms we consider acceptable. Further, the inability of one or more of our customers to pay amounts owed to us could adversely affect our business, financial condition, results of operations and cash flows.

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

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for and wage rates of qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, we rely on independent third-party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. Shortages of and increased costs for drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our operations 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.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of natural gas lines, trucks and transportation barges owned by third parties. In general, we do not control these transportation facilities and our access to them may be limited or denied. In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. A significant disruption in the availability of these transportation facilities or our compression and other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations.

With respect to our Utica/Marcellus acreage where we are focusing a portion of our exploration and development activity, operations may be delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting and the completion of facilities by our midstream service provider. Capital constraints could limit the construction of new pipelines and gathering systems and the providing or expansion of trucking services by third parties in the Utica/Marcellus and the other areas in which we operate. As a result, we may experience delays or curtailments in producing and selling our natural gas, oil and NGL. In such event, we might have to shut in or curtail our wells awaiting a pipeline connection or capacity or sell natural gas, oil or NGL production at significantly lower prices than those quoted on NYMEX or than we currently project, 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.

We are required to pay fees to some of our midstream service providers based on minimum volumes regardless of actual volume throughput.

We have contracts with some of our third-party service providers for gathering, processing and transportation services with minimum volume delivery commitments under which we are obligated to pay certain fees on minimum volumes regardless of actual volume throughput. As of December 31, 2025, our aggregate long-term contractual obligation under these agreements was approximately $1.0 billion. These fees could be significant and may have a material adverse effect on our results of operations.

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

Concerns over global economic conditions, tariffs, energy costs, geopolitical issues, inflation, the availability and cost of credit and the European, Asian and the United States financial markets have contributed to economic volatility and diminished expectations for the global economy. Historically, concerns about global economic growth have had a significant impact on global financial markets and commodity prices. If the economic 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.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in 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, 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. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have in the past precipitated, and may in the future precipitate, an economic slowdown.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our 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 oil, natural gas 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. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, have been and may become the target of cyberattacks or information security breaches that could result in the 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, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyberattack involving our information systems and related infrastructure, or that of our business associates, 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 customers', suppliers' or royalty owners' 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.

In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems for protecting against cybersecurity risks may not be sufficient. As cyberattacks continue to evolve, including those leveraging artificial intelligence, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyberattacks. In addition, new laws and regulations governing data privacy, cybersecurity, and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate costs, and any failure to comply with these laws and regulations could result in significant penalties and legal liability.

We may engage in acquisition and divestiture activities that involve substantial risks.

We may make acquisitions that complement or expand our current areas of operations. If we are unable to make attractive acquisitions, our future growth could be limited. Furthermore, even if we do make acquisitions, they may not result in an increase in our cash flow from operations or otherwise result in the benefits anticipated due to various risks, including, but not limited to:

- mistaken estimates or assumptions about reserves, potential drilling locations, revenues and costs, including synergies and the overall costs of equity or debt;
- difficulties in integrating the operations, technologies, products and personnel of the acquired assets or business; and
- unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections prove inadequate, including environmental liabilities and title defects.

In addition, from time to time, we may sell or otherwise dispose of certain of our properties or businesses as a result of an evaluation of our asset portfolio or to help enhance our liquidity. These transactions also have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets or businesses and potential post-closing claims for indemnification. Moreover, volatility in commodity prices may result in fewer potential bidders, unsuccessful sales efforts and a higher risk that buyers may seek to terminate a transaction prior to closing.

Environmental, Legal and Regulatory Risks

We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.

Our operations are subject to extensive federal, state, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGL, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. 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. For example, in March 2024, the United States Environmental Protection Agency ("USEPA") issued its final methane rules to reduce methane emissions from both new and existing oil and natural gas facilities and the Inflation Reduction Act of 2022 ("IRA 2022") established the Methane Emissions Reduction Program, which imposes a charge on methane emissions from the same facilities, the rule for which was finalized in November 2024. However, the methane emissions charge rule was repealed in February 2025 and the imposition of the charge under the IRA 2022 was postponed until 2034 under the One Big Beautiful Bill Act of July 2025. In December 2025, the USEPA issued a final rule extending several compliance deadlines and timeframes associated with the 2024 methane rules. Further, the BLM issued a final Methane Waste Prevention Rule on April 10, 2024. The rule adds additional requirements for operators on federal and Indian leases and includes new air quality requirements along with waste prevention provisions. In November 2025, BLM announced it will delay enforcement of two provisions of the Waste Prevention Rule that had been scheduled to take effect in December 2025 as it reviews the underlying rule and considers revisions. Litigation challenging the 2024 rule is currently held in abeyance. Constrained supply chain for environmental control devices along with the significant estimated costs of compliance with these new and proposed rules could have a material impact on our operations. 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. Regulatory changes could, among other things, restrict production levels, impose price controls, alter environmental protection requirements 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 or 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. As is discussed below this is particularly true of changes related to pipeline safety, seismic activity, hydraulic fracturing, climate change and endangered species designations. As of January 2025, however, the Trump Administration issued a series of executive orders that signal a shift in the United States' energy polices, including directing federal agencies to identify and exercise emergency authorities to facilitate conventional energy production, transportation, and refining, and call for the use of emergency regulations to expedite energy infrastructure projects, promote energy exploration and production on federal lands and waters, and mandate a review of existing regulations that may burden domestic energy development.

Pipeline Safety. The pipeline assets owned by our midstream service providers are subject to stringent and complex regulations related to pipeline safety and integrity management. The Pipeline and Hazardous Materials Safety Administration ("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 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. Further, legislation funding 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. At this time, we cannot predict the cost of these requirements or other potential new or amended regulations, but they could be significant, and any such costs incurred by our midstream service providers could result in increased midstream gathering and processing expenses for us. Moreover, violations of pipeline safety regulations by our midstream service providers could result in the imposition of significant penalties which may impact the cost or availability of pipeline capacity necessary for our operations.

Seismic Activity. Earthquakes in some of our operating areas and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. For example, the OCC issued guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing or water disposal activities. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we could be subject to third-party lawsuits seeking damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. Several states including New York, Maryland and Vermont, have banned or imposed a moratorium on the use of high-volume hydraulic fracturing. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. There have also been certain governmental reviews that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Governments may continue to study hydraulic fracturing. We cannot predict the outcome of future studies, but based on the results of these studies to date, federal and state legislatures and agencies may seek to further regulate or even ban hydraulic fracturing activities. In addition, if existing laws and regulations with regard to hydraulic fracturing are revised or reinterpreted or if new laws and regulations become applicable to our operations through judicial or administrative actions, our business, financial condition, results of operations and cash flows could be adversely affected.

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 greenhouse gas emissions, such as carbon dioxide and methane, and incentivizing energy conservation or the use of alternative energy sources. Policy makers at both the federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations or taxes on greenhouse gas emissions and encourage consumers to the alternative energy sources. The IRA 2022, both imposes new climate related requirements on oil and gas operations and appropriates significant federal funding for renewable energy initiatives. Also, for the first time ever, the law imposes a fee on GHG emissions from certain facilities. The emissions fee and funding provisions of the IRA 2022 could increase our operating costs and accelerate the transition away from fossil fuels, which could in turn adversely affect our business, results of operations and financial position. Under the Trump Administration, however, there has been a shift away from the previous administration's GHG program. For example, in February 2025, the U.S. House and Senate approved a joint resolution of disapproval under the Congressional Review Act to repeal the methane emissions charge rule, which President Trump signed into law. In September 2025, the USEPA announced a proposal to end the GHG Reporting Program for all sectors except petroleum and natural gas systems (excluding reporting for natural gas distribution, which would also be eliminated under the proposal) and deferring reporting for petroleum and natural gas systems until 2034. In December 2025, the USEPA issued a final rule extending several compliance deadlines and timeframes associated with its 2024 methane rules. On February 12, 2026, the USEPA announced the repeal of its 2009 “Endangerment Finding” under the Clean Air Act, which found that GHGs endanger the public health and welfare of current and future generations and emissions of GHGs from motor vehicles contribute to GHG pollution. The repeal calls into question EPA's authority to regulate GHGs, as well as EPA's prior scientific assessment of climate change risks. Litigation regarding the repeal is anticipated and it is unclear how the repeal will impact EPA's regulation of GHG emissions going forward. However, state and local GHG initiatives may continue despite shifts in the federal approach to climate change.

States in which we operate have imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally focused on the development of cap and trade 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 or other initiatives to incentivize the use of renewable energy could reduce the demand for oil and gas, thereby adversely impacting our earnings, cash flows and financial position. Cap and trade programs offer greenhouse gas emission allowances that are gradually reduced over time. A cap and trade program or expanded use of cap and trade programs at the state level could impose direct costs on us through the purchase of allowances and could impose indirect costs by incentivizing consumers to shift away from fossil fuels. In addition, federal or state carbon taxes could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Members of the investment community have also begun to screen companies such as ours for sustainability performance, including practices related to greenhouse gases and climate change, before investing in our common units. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, and we may be forced to implement technologies that are not economically viable to improve our sustainability performance and to meet the specific requirements to perform services for certain customers. If we are unable to meet the sustainability standard or investment, lending, ratings, or voting criteria and policies set by these parties, we may lose investors, investors may allocate a portion of their capital away from us, we may become a target for sustainability-focused activism, our cost of capital may increase, the price of our securities may be negatively impacted, and our reputation may also be negatively affected.

These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity. Furthermore, increasing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

Severe weather events, such as storms, hurricanes, droughts, or floods, which may be exacerbated by climate change, could have an adverse effect on our operations and could increase our costs. Potential adverse effects could include damages to our facilities, the costs of less efficient or non-routine operating practices necessitated by weather events, or increased costs for insurance coverage. If climate changes result in more intense or frequent severe weather events, the physical and disruptive effects could have a material adverse impact on our operations and assets.

Air Emissions. The US Federal Clean Air Act and associated state laws and regulations restrict the emission of air pollutants from many sources, including oil and natural gas operations. New facilities may be required to obtain permits before operations can commence, and existing facilities may be required to obtain additional permits, and incur capital costs, in order to remain in compliance. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. In general, we believe that compliance with the Clean Air Act and similar state laws and regulations will not have a material impact on our operations or financial condition.

Endangered Species. The Endangered Species Act (“ESA”) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, including in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells.

In our Utica/Marcellus and SCOOP operations, we make an effort to reuse/recycle all produced water from production and completion activities through our fracture stimulation operations when active. While our objective is to recycle or share 100% of all produced water, we do inject water into third-party commercially operated disposal wells in line with all state and federal mandated practices and cease produced water recycle whenever fracture stimulation operations are idle once sharing opportunities with other operators have been exhausted. In the state of Ohio, all water used during drilling operations is disposed of through injection into third-party salt water disposal wells regulated by applicable state agencies.

Increased attention to sustainability matters may impact our business, financial results, or stock price.

Standards and expectations regarding carbon accounting and the processes for measuring and counting GHG emissions and GHG emission reductions are evolving, and it is possible that our approach to measuring both our emissions and our approaches to reducing emissions may be, either currently by some stakeholders or at some future point, considered inconsistent with common or best practices. A failure to comply with investor or customer expectations and standards, which are evolving, or if we are perceived to not have responded appropriately to the growing concern for sustainability 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.

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 sustainability matters. These ratings are used by some investors to inform their investment and voting decisions. We may take certain actions to improve the sustainability profile of our company and/or products, but we cannot guarantee that such actions will have the desired effect. Unfavorable sustainability 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.

Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and gas industry. For example, legislative proposals have been introduced in the U.S. Congress in the past that, if enacted, would (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) repeal the percentage depletion allowance for oil and natural gas properties and (iii) extend the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. In addition, at the state level, legislative changes imposing increased taxes on oil and gas production have periodically been considered in Ohio and Oklahoma. These proposed changes in the U.S. federal and state tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flows.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate our costs as we collect, use, share and store personal data related to royalty owners. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. For example, the California Consumer Privacy Act ("CCPA"), as amended by the California Privacy Rights Act ("CPRA"), establishes certain transparency rules and creates new data privacy rights for individuals, including limitations on our use of certain sensitive personal information and more ability for individuals to control the purposes for which their data is shared with third parties. The CPRA also provides for statutory fines for data security breaches or other CPRA violations. Meanwhile, many other states enacted, and others have considered, privacy laws like the CPRA. We will continue to monitor and assess the impact of these state laws, which may impose substantial penalties for violations, impose significant costs for investigations and compliance, require us to change our business practices, allow private class-action litigation and carry significant potential liability for our business should we fail to comply with any such applicable laws.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in heightened risk of litigation, including private rights of action, and proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of cyber incidents or attacks, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

Risks Associated with an Investment in Us

The market price of our securities is subject to volatility.

The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading that develops with our common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, future sales of additional stock and changes in our capital structure, compliance with governmental regulations and taxation laws, actual or anticipated variations in our operating results and cash flow, allocation of free cash flow including any determination by our board of directors regarding repurchasing stock, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this Part I, Item 1A of this Annual Report on Form 10-K.

Future sales or the availability for sale of substantial amounts of our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and could impair our ability to raise capital through future sales of equity securities.

A significant percentage of our common stock is held by a single investor. In connection with our emergence from bankruptcy protection in 2021, we entered into the Registration Rights Agreement pursuant to which we have agreed to file a registration statement with the SEC to facilitate potential future sales of our common stock by such investors. Sales of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur (such as upon the filing of the aforementioned registration statement), could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We cannot predict the effect that future sales of our common stock will have on the price at which the common stock trades. Sales of substantial amounts of our common stock, or the perception that such sales could occur, may adversely affect the trading price of our common stock.

Certain of our stockholders own a significant portion of our outstanding equity securities and their interests may not always coincide with the interests of other holders of the common stock.

A large percentage of our equity is held by a relatively small number of investors. As a result, these investors could have significant influence over all matters presented to our stockholders for approval, including election and removal of our directors, change in control transactions and the outcome of all actions requiring majority stockholder approval.

The interests of these investors may not always coincide with the interests of the other holders of the common stock, and the concentration of control in these investors may limit other stockholders' ability to influence corporate matters. The concentration of ownership and voting power of these investors may also delay, defer or even prevent an acquisition by a third-party or other change of control transactions of our Company. This may make some transactions more difficult or impossible without their support, even if such events are in the best interests of our other stockholders. In addition, the concentration of voting power may adversely affect the trading price and liquidity of the common stock.

There may be future dilution of our common stock, which could adversely affect the market price of our common stock.

We are not restricted from issuing additional shares of our common stock. In the future, we may issue shares of our common stock to raise cash for future capital expenditures, acquisitions or for general corporate purposes. We may also issue securities that are convertible into, exchangeable for or that represent the right to receive our common stock. Lastly, we currently issue restricted stock units and performance vesting restricted stock units to certain employees and directors as part of their compensation. Any of these events will dilute our shareholders' ownership interest in Gulfport and may reduce our earnings per share and have an adverse effect on the price of our common stock.

Our amended and restated certificate of incorporation provides, subject to certain exceptions, that the Court of Chancery of the State of Delaware will be the sole and exclusive forum for certain stockholder litigation matters, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or stockholders.

Our amended and restated certificate of incorporation provides, subject to limited exceptions, that the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf; (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors or officers to us, our stockholders, our creditors or other constituents; (iii) any action asserting a claim against us, any director or our officers arising pursuant to any provision of the DGCL, our certificate of incorporation or our by-laws; or (iv) any action asserting a claim against us, any director or our officers that is governed by the internal affairs doctrine. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or any of our directors or officers or stockholders which may discourage lawsuits with respect to such claims. Alternatively, if a court were to find the choice of forum provision contained in our certificate of incorporation to be inapplicable or unenforceable in an action, we may incur additional costs associated with resolving such action in other jurisdictions, which could have a material adverse effect on our business, financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Enterprise Risk Management

Gulfport increasingly relies on digital technology to optimize our business. As our reliance on technology expands, we are exposed to additional cyber risks, which we focus on assessing, identifying and managing. These risks include, but are not limited to: financial risks, operational risks, safety concerns, employee and owner personal information and violation of data privacy or security laws.

Managing Material Risks & Integrated Overall Risk Management

We take an integrated approach to assessing and identifying cybersecurity risks and threats. At the corporate level, cybersecurity is identified as a key risk within our Enterprise Risk Management ("ERM") program. Our management of cyber risk is based on the National Institute of Standards and Technology's ("NIST") cybersecurity framework combined with the Center for Internet Security's ("CIS") control framework.

We utilize a defense-in-depth approach, layering security starting with cloud-based tools through our perimeter all the way to the client and server endpoints with End Point Detection and Response solutions. We continue to invest and align advances in technology to strengthen our security posture. During 2025, our investment focused on continuous improvement in cyber detections for our operations technology environment, threat and vulnerability management and data loss prevention.

Cyber risks and incidents are categorized by severity, evaluated for materiality, responded to based on defined incident response playbooks and then remediated accordingly. We perform organized tabletop exercises to test these practices and identify areas where opportunities for improvement exist.

We acknowledge that—even with advanced security tools—we are only as strong as the people that use our technology. That is why we design phishing simulations and require multiple security training courses for every employee annually. Our partnerships with law enforcement, the Oil and Natural Gas Information Sharing Center and our third-party partners continually mature our cyber program as threats evolve.

Engaging Third Parties on Risk Management

Recognizing the complexity and evolving nature of cybersecurity risk, we leverage strategic external partnerships to assess and mitigate cybersecurity threats. For example, in addition to our security analysts, we partner with third parties that provide 24/7 security operations monitoring, enhancing our response time. We are also audited by third parties for compliance with information security standards and to assess vulnerabilities, providing additional expertise that strengthens our security posture.

Managing Third Party Risk

We recognize the risks associated with the use of vendors, service providers and other third parties that provide information system services to us, process information on our behalf, or have access to our information systems, and we have processes in place to oversee and manage these risks. We maintain ongoing monitoring to ensure compliance with our cybersecurity standards.

Risks from Cybersecurity Incidents

As of December 31, 2025, and for the past five years, we have identified no security incidents or breaches that are material, or likely to be material, to our business strategy, results or financial condition.

Cybersecurity Governance

We involve multiple levels of oversight as a part of our approach to cybersecurity risk management.

Risk Management Personnel

Cybersecurity remains a top identified enterprise-wide risk for our business and is overseen by our Chief Information Officer who is responsible for identifying and mitigating information security risks. Our current CIO has 20 years of industry experience and over 10 years of experience with the development, training and controls of effective global enterprise cybersecurity programs. The CIO's responsibilities include but are not limited to: (i) reviewing our enterprise risk register and functional risk register; (ii) maintaining adequate processes to manage the identified risks under our cybersecurity program; (iii) analyzing logs of cybersecurity threats and vulnerabilities; (iv) overseeing prevention, detection, mitigation and remediation efforts; and (v) developing, maintaining, and ensuring team familiarity with the above-mentioned incident response plan. Additionally, we maintain an experienced information technology team at the employee level that supports our Chief Information Officer in implementing our cybersecurity program and internal reporting, security and mitigation functions.

Board of Director Oversight

The Audit Committee receives a detailed cybersecurity update annually from the Chief Information Officer and receives a cybersecurity update quarterly through the ERM program as a key risk.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1 and in the Supplemental Information on Oil and Gas Exploration and Production Activities in Note 20 of our consolidated financial statements.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business.

While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

The information with respect to this Item 3. "Legal Proceedings" is set forth in Note 18 of our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Common Stock

Shares of our common stock are listed on the NYSE under the symbol "GPOR". See Note 6 of our consolidated financial statements for further discussion of our common stock.

Shareholders

At the close of business on February 11, 2026, there were approximately 34,358 holders of record of our common stock.

Dividends

During the years ended December 31, 2025, 2024 and 2023, the Company has not paid dividends on our common stock. The declaration and payment of any future common stock dividend will be at the full discretion of the Board of Directors and will depend on our financial results, cash requirements, future prospects and other factors deemed relevant by our Board. Our Credit Facility also requires us to meet certain financial covenants at the time dividend payments are made.

During the years ended December 31, 2025, 2024 and 2023, the Company paid $1.7 million, $4.2 million and $4.8 million, respectively, of cash dividends to holders of our preferred stock. During the third quarter of 2025, the Company redeemed its remaining outstanding preferred stock and no cash dividends were paid after September 5, 2025 (the "Redemption Date").

Issuer Purchases of Equity Securities

In November 2021, the Company's Board of Directors approved the Repurchase Program to acquire up to $100 million of common stock, which has subsequently been increased up to $1.5 billion and extended through December 31, 2026. Purchases under the Repurchase Program may be made from time to time in open market or privately negotiated transactions, and will be subject to available liquidity, market conditions, credit agreement restrictions, applicable legal requirements, contractual obligations and other factors. The Repurchase Program does not require the Company to acquire any specific number of shares of common stock. The Company intends to purchase shares under the Repurchase Program with available funds while maintaining sufficient liquidity to fund its capital development program. The Repurchase Program may be suspended from time to time, modified, extended or discontinued by the Board of Directors at any time. As of December 31, 2025, the Company had repurchased 7.4 million shares for $920.4 million at a weighted average price of $125.19 per share since the inception of the Repurchase Program.

The following table provides a summary of our common stock repurchase activity for the three months ended December 31, 2025:

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total number of shares purchased as part of publicly announced plans or programs	Approximate maximum dollar value of shares that may yet be purchased under the plans or programs
October 1 - October 31	179,419	$ 183.93	179,419	$ 681,611,000
November 1 - November 30	219,614	$ 209.46	219,614	$ 635,611,000
December 1 - December 31	265,630	$ 210.83	265,617	$ 579,611,000
Total	664,663	$ 203.11	664,650	

(1) We repurchased and canceled 13 shares of our common stock at a weighted average price of $201.85 to satisfy tax withholding requirements incurred upon the vesting of restricted stock unit awards during December 2025.

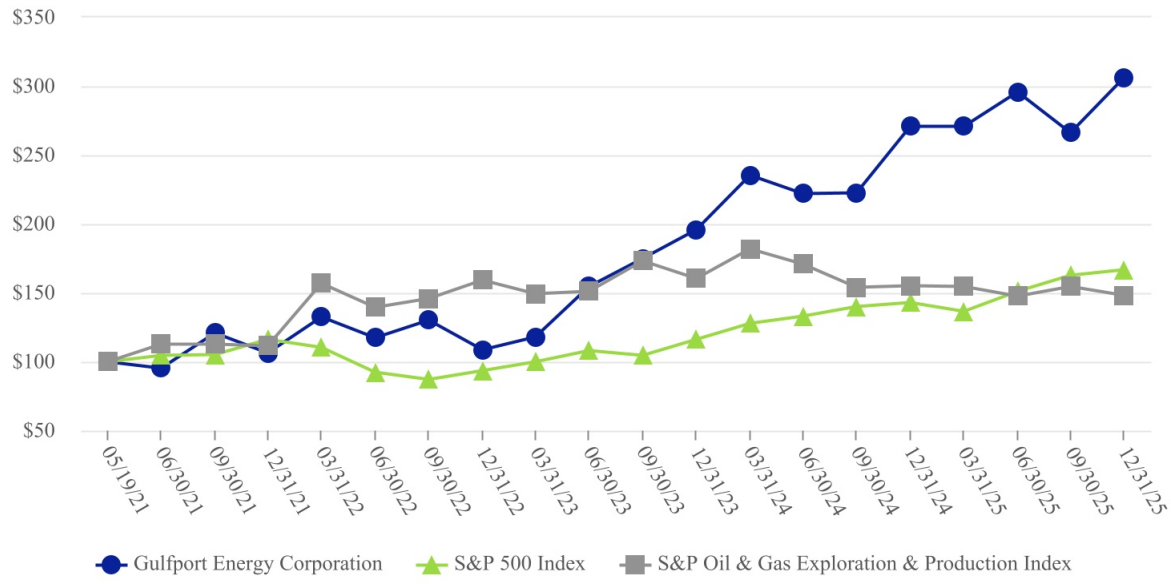
Recent Sales of Unregistered Securities

None.

Stock Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The performance graph below illustrates changes over the period of May 19, 2021, through December 31, 2025, in cumulative total stockholder return on the common stock as measured against the cumulative total return of the S&P 500 Index and the S&P Oil & Gas Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from May 19, 2021, to December 31, 2025.



ITEM 6. [RESERVED]

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

The following discussion and analysis represents management's perspective of our business, financial condition and overall performance. 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. "Financial Statements and Supplementary Data" of this report. The following information updates the discussion of Gulfport's financial condition provided in its 2024 Annual Report on Form 10-K filing and compares the results of operations for the year ended December 31, 2025 to the year ended December 31, 2024. Discussions of our results from 2023 to 2024 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2024.

Overview

Gulfport is an independent natural gas-weighted exploration and production company with assets primarily located in the Appalachia and Anadarko basins. Our principal operations target the Utica and Marcellus formations in eastern Ohio and the SCOOP Woodford and Springer formations in central Oklahoma. Our strategy is to develop our assets in a safe, environmentally responsible manner, while generating sustainable cash flow, improving margins and operating efficiencies and returning capital to shareholders. To accomplish these goals, we generally allocate capital to projects we believe offer the highest rate of return and we deploy leading drilling and completion techniques and technologies in our development efforts.

Recent Developments

Share Repurchase Program and Redemption of Preferred Stock

On August 4, 2025, the Company's Board of Directors approved an increase to the authorized Repurchase Program from $1.0 billion to $1.5 billion (including the redemption of preferred stock noted below) and extended the authorization through December 31, 2026.

On August 5, 2025, Gulfport issued a notice of redemption for its preferred stock for cash. During the period between the date of notice of the redemption and the Redemption Date, 28,907 shares of preferred stock were converted into approximately 2.1 million shares of common stock. On the Redemption Date, the Company redeemed the remaining 2,449 shares of preferred stock for cash totaling $31.3 million. Additionally, direct transaction-related costs of $1.1 million were incurred as part of the redemption.

During the year ended December 31, 2025, the Company repurchased 1.8 million shares for $336.3 million at a weighted average price of $188.65 per share. As of December 31, 2025, the Company repurchased 7.4 million shares for $920.4 million at a weighted average price of $125.19 per share since the inception of the Repurchase Program.

Credit Facility

On October 30, 2025, the Company entered into the Borrowing Base Reaffirmation Agreement and Fifth Amendment to Credit Agreement (the “Fifth Amendment”). The facility provides for a borrowing base of $1.1 billion and aggregate elected commitments of $1.0 billion.

Tariffs and Trading Relationships

In 2025 and 2026, the U.S. government threatened, announced and, in certain cases, rescinded, tariffs on several foreign jurisdictions and imports into the United States, which led, and may continue to lead, to the imposition of retaliatory tariffs and other measures taken by foreign jurisdictions. There is significant uncertainty as to the scope and durability of existing and future tariff measures, as well as the ultimate effects of the tariffs on economic conditions.

One Big Beautiful Bill Act

On July 4, 2025, the President signed into law the legislation commonly referred to as the One Big Beautiful Bill Act (“OBBBA”), which introduces significant changes to U.S. federal tax law. Key provisions of the OBBBA that are relevant to the Company include modifications to the limitations on the deductibility of interest expense under Section 163(j) of the Internal Revenue Code and adjustments to bonus depreciation rules.

2025 Operational and Financial Highlights

During 2025, we had the following notable achievements:

- Reported total net production of 1,039 MMcfe per day.
- Generated $803.2 million of operating cash flows.
- Turned to sales 32 gross operated (31.8 net) wells.
- Redeemed outstanding preferred stock, simplifying our capital structure and eliminating future dividend obligations on the preferred stock.
- Expanded common share repurchase program to $1.5 billion and returned $336.3 million to shareholders through the repurchase of 1.8 million shares (including the underlying shares of common stock into which the preferred stock was convertible) at a weighted average price of $188.65 per share.
- Maintained a strong balance sheet and low financial leverage, exiting the year with total liquidity of $806.1 million.
- Achieved MIQ certification for all Appalachia assets for the third consecutive year.
- Reported year-end estimated net proved reserves of 4.3 Tcfe.

Business and Industry Outlook

The Company's primary focus going into 2026 is its continued attention on reducing cycle times and operating costs to improve margins and ultimately enhance our expected free cash flow generation. Throughout the year, we plan to maintain capital discipline, prioritizing free cash flow generation and preserving our strong financial position, while returning capital to shareholders and increasing our resource depth through incremental leasehold opportunities.

In 2025, natural gas prices continued to be volatile as spot prices ranged from $2.65 to $9.86 per MMBtu. Henry Hub averaged $3.52 per MMBtu in 2025 vs $2.19 per MMBtu in 2024. As we look into 2026, we expect continued volatility in natural gas prices. To mitigate our exposure to commodity market volatility and to help provide a level of certainty around our financial strength, we have entered into a combination of natural gas swaps and collars, representing approximately 52% of our expected 2026 gas production, at an average floor price of $3.74 per Mcf.

Our 2026 capital expenditure program is expected to be in a range of $400 million to $430 million, including $35 million to $40 million on maintenance land and seismic investments.

Results of Operations

Comparison of the Year Ended December 31, 2025 and 2024

We reported net income of $427.8 million for the year ended December 31, 2025, compared to a net loss of $261.4 million for the year ended December 31, 2024. The material changes that led to the increase in net income are further discussed by category on the following pages. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

Natural Gas, Oil and Condensate and NGL Production and Pricing (sales totals in thousands)

	Year Ended December 31, 2025	Year Ended December 31, 2024
Natural gas (MMcf/day)		
Utica & Marcellus production volumes	777	810
SCOOP production volumes	150	157
Total production volumes	927	968
Total sales	$ 1,056,429	$ 714,160
Average price without the impact of derivatives ($/Mcf)	$ 3.12	$ 2.02
Impact from settled derivatives ($/Mcf)	$ 0.14	$ 0.80
Average price, including settled derivatives ($/Mcf)	$ 3.26	$ 2.82
Oil and condensate (MBbl/day)		
Utica & Marcellus production volumes	5	2
SCOOP production volumes	1	2
Total production volumes	6	4
Total sales	$ 133,644	$ 101,589
Average price without the impact of derivatives ($/Bbl)	$ 59.12	$ 69.64
Impact from settled derivatives ($/Bbl)	$ 4.04	$ 0.11
Average price, including settled derivatives ($/Bbl)	$ 63.16	$ 69.75
NGL (MBbl/day)		
Utica & Marcellus production volumes	6	3
SCOOP production volumes	6	8
Total production volumes	12	10
Total sales	$ 133,454	$ 112,855
Average price without the impact of derivatives ($/Bbl)	$ 29.30	$ 29.56
Impact from settled derivatives ($/Bbl)	$ (0.07)	$ (0.56)
Average price, including settled derivatives ($/Bbl)	$ 29.23	$ 29.00
Total (MMcfe/day)		
Utica & Marcellus production volumes	841	842
SCOOP production volumes	197	212
Total production volumes	1,039	1,054
Total sales	$ 1,323,527	$ 928,604
Average price without the impact of derivatives ($/Mcfe)	$ 3.49	$ 2.41
Impact from settled derivatives ($/Mcfe)	$ 0.15	$ 0.73
Average price, including settled derivatives ($/Mcfe)	$ 3.64	$ 3.14

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
Natural gas	$ 1,056,429	$ 714,160	48 %
Oil and condensate	133,644	101,589	32 %
NGL	133,454	112,855	18 %
Total natural gas, oil and condensate and NGL sales	$ 1,323,527	$ 928,604	43 %

The increase in natural gas sales without the impact of derivatives when comparing the year ended December 31, 2025, to the year ended December 31, 2024, was primarily due to a 55% increase in realized natural gas prices, partially offset by a 4% decrease in sales volumes. The realized price change was primarily driven by the increase in the average Henry Hub gas index from $2.27 per Mcf in the year ended December 31, 2024, to $3.43 per Mcf during the year ended December 31, 2025. The 4% decrease in natural gas production was primarily due to natural declines partially offset by our 2024 and 2025 development programs and the impact of unplanned, third-party midstream outages and constraints.

The increase in oil and condensate sales without the impact of derivatives when comparing the year ended December 31, 2025, to the year ended December 31, 2024, was due to a 55% increase in sales volumes, partially offset by a 15% decrease in realized oil prices. The 55% increase in oil and condensate production was primarily due to commencement of sales on new wells targeting the Utica and Marcellus liquids windows. The realized price change was primarily driven by the decrease in the average WTI crude index from $75.72 per barrel in the year ended December 31, 2024, to $64.81 per barrel during the year ended December 31, 2025.

The increase in NGL sales without the impact of derivatives when comparing the year ended December 31, 2025, to the year ended December 31, 2024, was due to a 19% increase in NGL sales volumes, partially offset by a 1% decrease in realized prices. The 19% increase in NGL production was primarily due to commencement of sales on new wells targeting the Utica and Marcellus liquids windows.

Natural Gas, Oil and NGL Derivatives (in thousands)

The total natural gas, oil and NGL volumes hedged for the year ended December 31, 2025 and 2024, represented approximately 73% and 80%, respectively, of our total sales volumes for the applicable year.

	Year Ended December 31, 2025	Year Ended December 31, 2024
Natural gas derivatives - fair value gains (losses)	$ 39,010	$ (251,019)
Natural gas derivatives - settlement gains	47,705	284,626
Total gains on natural gas derivatives	86,715	33,607
Oil and condensate derivatives - fair value (losses) gains	(3,468)	2,351
Oil and condensate derivatives - settlement gains	9,124	166
Total gains on oil and condensate derivatives	5,656	2,517
NGL derivatives - fair value gains (losses)	7,017	(4,442)
NGL derivatives - settlement losses	(332)	(2,155)
Total gains (losses) on NGL derivatives	6,685	(6,597)
Total gains on natural gas, oil and NGL derivatives	$ 99,056	$ 29,527

We recognize fair value changes on our natural gas, oil and NGL derivative instruments in each reporting period. The changes in fair value resulted from new positions and settlements that occurred during each period, as well as the relationship between contract prices and the associated forward curves. The change in the total gain for the year ended December 31, 2025 compared to the year ended December 31, 2024, was primarily the result of changes in futures pricing for oil, natural gas, and NGLs during each period. The net fair value gains of our hedging program totaled $42.6 million for the year ended December 31, 2025 compared to losses of $253.1 million for the year ended December 31, 2024. Settlement gains (losses) in the table above represent realized cash gains or losses to the instruments described in Note 12 of our consolidated financial statements. Our hedging program generated cash receipts of $56.5 million for the year ended December 31, 2025, compared to cash receipts of $282.6 million for the year ended December 31, 2024.

Lease Operating Expenses (in thousands, except per unit)

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
Lease operating expenses			
Utica & Marcellus	$ 61,661	$ 48,321	28 %
SCOOP	22,581	21,791	4 %
Total lease operating expenses	$ 84,242	$ 70,112	20 %
Lease operating expenses per Mcfe			
Utica & Marcellus	$ 0.20	$ 0.16	25 %
SCOOP	0.31	0.28	11 %
Total lease operating expenses per Mcfe	$ 0.22	$ 0.18	22 %

The increase in total LOE and per unit LOE for the year ended December 31, 2025, compared to the year ended December 31, 2024, was primarily the result of an increase in water hauling, repairs and maintenance and labor expenses in our Utica operations.

Taxes Other Than Income (in thousands, except per unit)

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
Production taxes	$ 21,408	$ 19,385	10 %
Property taxes	5,527	8,174	(32) %
Other	2,973	2,178	37 %
Total taxes other than income	$ 29,908	$ 29,737	1 %
Total taxes other than income per Mcfe	$ 0.08	$ 0.08	— %

The total and per unit taxes other than income for the year ended December 31, 2025, compared to the year ended December 31, 2024, remained consistent.

Transportation, Gathering, Processing and Compression (in thousands, except per unit)

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
Transportation, gathering, processing and compression	$ 358,938	$ 351,237	2 %
Transportation, gathering, processing and compression per Mcfe	$ 0.95	$ 0.91	4 %

Transportation, gathering, processing and compression for the year ended December 31, 2025, compared to the year ended December 31, 2024, increased on a total and per unit basis primarily as a result of an increase in the proportion of natural gas liquids and oil and condensate production.

Depreciation, Depletion and Amortization (in thousands, except per unit)

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
Depreciation, depletion and amortization of oil and gas properties	$ 302,024	$ 324,078	(7) %
Depreciation, depletion and amortization of other property and equipment	2,138	1,645	30 %
Total depreciation, depletion and amortization	$ 304,162	$ 325,723	(7) %
Total depreciation, depletion and amortization per Mcfe	$ 0.80	$ 0.84	(5) %

The total and per unit depreciation, depletion and amortization of our oil and gas properties for the year ended December 31, 2025, compared to the year ended December 31, 2024, decreased primarily due to a lower depletion rate resulting from a decline in our amortization base from the full cost ceiling test impairments recorded during 2024, combined with a decrease in our production. Our production decreased primarily due to natural declines and the impact of unplanned, third-party midstream outages and constraints, partially offset by our 2024 and 2025 development programs.

Impairment of Oil and Natural Gas Properties

At September 30, 2024 and December 31, 2024, the net book value of our oil and gas properties exceeded the calculated ceiling. As a result, we recorded a non-cash ceiling test impairment of $30.5 million in the third quarter and $342.7 million in the fourth quarter of 2024. The impairments resulted from declines in the full cost ceiling, which primarily resulted from the significant decrease in the 12-month average trailing price for natural gas. The 12-month average trailing price for natural gas in the third quarter and fourth quarter of 2024 was $2.21 per MMBtu and $2.13 MMBtu, respectively.

We did not incur an impairment of oil and natural gas properties during any quarter in 2025.

General and Administrative Expenses (in thousands, except per unit)

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
General and administrative expenses, gross	$ 84,004	$ 82,478	2 %
Reimbursed from third parties	(16,269)	(14,582)	12 %
Capitalized general and administrative expenses	(25,247)	(25,338)	— %
General and administrative expenses, net	$ 42,488	$ 42,558	— %
General and administrative expenses, net per Mcfe	$ 0.11	$ 0.11	— %

The increase in total and per unit general and administrative expenses for the year ended December 31, 2025, compared to the year ended December 31, 2024, was primarily driven by increases in employee compensation and legal expense related to the matters disclosed in Note 18 of our consolidated financial statements.

Interest Expense (in thousands, except per unit)

	Year Ended December 31, 2025	Year Ended December 31, 2024	% Change
Interest on 2026 Senior Notes	$ 777	$ 31,417	(98) %
Interest on 2029 Senior Notes	43,875	13,163	233 %
Interest on Credit Facility	9,390	14,143	(34) %
Amortization of loan costs	5,258	4,208	25 %
Capitalized interest	(6,154)	(4,771)	29 %
Other	1,131	1,822	(38) %
Total interest expense	$ 54,277	$ 59,982	(10) %
Interest expense per Mcfe	$ 0.14	$ 0.16	(13) %

Total interest expense for the year ended December 31, 2025, decreased 10% compared to the year ended December 31, 2024. The decrease was primarily due to lower borrowings and a reduced interest rate on our Credit Facility. In the third quarter of 2024, we retired the 2026 Senior Notes and issued the 2029 Senior Notes. Although the interest rate on the 2029 Senior Notes is lower than that of the 2026 Senior Notes, the higher principal balance largely offset the effect of the lower interest rate, resulting in little overall impact on interest expense between periods. We capitalized $6.2 million of interest during the period, compared to $4.8 million in the prior year. See Note 4 of our consolidated financial statements for further details regarding our Credit Facility, issuance of the 2029 Senior Notes and retirement of the 2026 Senior Notes.

Loss on Debt Extinguishment

In September 2024, Gulfport Operating purchased and retired $524.3 million of the 2026 Senior Notes in a tender offer using net proceeds from the 2029 Senior Notes offering. The 2026 Senior Notes were tendered at an average price equal to 102.3% of the principal amount. The retirement of the 2026 Senior Notes resulted in a loss on debt extinguishment of $13.4 million, which included cash costs of $12.9 million.

Income Taxes

On July 4, 2025, the OBBBA, which includes a broad range of tax reform provisions, was signed into law in the United States. We completed our assessment of the OBBBA's provision and incorporated the applicable impacts into our current tax expense and deferred tax assets and liabilities. The provisions did not have a significant effect on the Company’s tax positions for the current period.

For the year ended December 31, 2025, our effective tax rate was 21.26% and an income tax expense of $115.5 million. For the year ended December 31, 2024, our effective tax rate was 17.66% and an income tax benefit of $56.1 million. See Note 10 of our consolidated financial statements for further discussion of our income tax expense.

Liquidity and Capital Resources

Overview. We strive to maintain sufficient liquidity to ensure financial flexibility, withstand commodity price volatility, fund our development projects, operations and capital expenditures and return capital to shareholders. We utilize derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty to the Company’s cash flows. We generally fund our operations, planned capital expenditures and any share repurchases with cash flow from our operating activities, cash on hand, and borrowings under our Credit Facility. Additionally, we may access debt and equity markets and sell properties to enhance our liquidity. There is no guarantee that the debt or equity capital markets will be available to us on acceptable terms or at all.

For the year ended December 31, 2025, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations and access to the debt markets, and our primary uses of cash have been for development of our oil and natural gas properties, share repurchases, interest payments, dividend payments on our preferred stock and discretionary acreage acquisitions.

We believe our annual free cash flow generation, borrowing capacity under the Credit Facility and cash on hand will provide sufficient liquidity to fund our operations, capital expenditures, interest expense and share repurchases during the next 12 months and the foreseeable future.

To the extent actual operating results, realized commodity prices or uses of cash differ from our assumptions, our liquidity could be adversely affected. See Note 4 of our consolidated financial statements for further discussion of our debt obligations, including principal and carrying amounts of our senior notes.

As of December 31, 2025, we had $1.8 million of cash and cash equivalents compared to $1.5 million as of December 31, 2024, and a net working capital deficit of $115.9 million as of December 31, 2025, compared to net working deficit of $114.2 million as of December 31, 2024. As of December 31, 2025, our net working capital deficit includes no debt due in the next 12 months. Our total principal amount of funded debt as of December 31, 2025, was $797.0 million compared to $713.7 million as of December 31, 2024. See Note 4 of our consolidated financial statements for further discussion of our debt obligations, including principal and carrying amounts of our senior notes.

As of February 19, 2026, we had $2.1 million of cash and cash equivalents, $219.0 million borrowings under our Credit Facility, $48.7 million of letters of credit outstanding and $650.0 million of outstanding 2029 Senior Notes.

Debt. In May 2025, we redeemed the remaining $25.7 million principal amount of our 8.00% senior unsecured notes due 2026 at par. As of December 31, 2025, we had $650.0 million of our 6.75% senior unsecured notes due 2029, which is classified as long-term on our consolidated balance sheet. Based on amounts outstanding at year-end, anticipated annual cash interest payments on our fixed-rate debt total approximately $43.9 million. In October 2025, we entered into the Fifth Amendment to our Credit Agreement, which reaffirmed the borrowing base at $1.1 billion and maintained elected commitments at $1.0 billion, with a maturity date of September 12, 2028. As of December 31, 2025, we had $147.0 million of borrowings outstanding, no letters of credit issued, and were in compliance with all financial covenants. At year-end, we had approximately $804.3 million of availability under the Credit Facility, which remains subject to semi-annual borrowing base redeterminations based primarily on projected future cash flows, with the next scheduled redetermination occurring in the spring of 2026.

We may continue to use a combination of cash, borrowings and issuances of our common stock or other securities to retire our outstanding debt through privately negotiated transactions, open market repurchases, tender offers or otherwise, but we are under no obligation to do so.

See Note 4 of our consolidated financial statements for additional discussion of our outstanding debt.

Dividends on Preferred Stock. As discussed in Note 5 of our consolidated financial statements, holders of preferred stock were entitled to receive cumulative quarterly dividends at a rate of 10% per annum of the Liquidation Preference with respect to cash dividends and 15% per annum of the Liquidation Preference with respect to dividends paid in kind as additional shares of preferred stock ("PIK Dividends"). We had the option to pay either cash dividends or PIK Dividends on a quarterly basis. On September 5, 2025, the Company redeemed all of its outstanding preferred stock. During the years ended December 31, 2025 and 2024, the Company paid $1.7 million and $4.2 million, respectively, of cash dividends to holders of our preferred stock. No cash dividends were paid after the Redemption Date.

Supplemental Guarantor Financial Information. The 2029 Senior Notes are guaranteed on a senior unsecured basis by Gulfport and certain of Gulfport's wholly owned subsidiaries (collectively, the "2029 Senior Notes Guarantors" and, together with the 2026 Senior Notes Guarantors, the "Guarantors") and certain future subsidiaries of Gulfport that become borrowers or guarantors under any credit agreement with an aggregate principal amount outstanding or commitment amount in excess of $15 million. The 2029 Senior Notes Guarantors are 100% owned by the Parent, and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the 2029 Senior Notes Guarantors to obtain funds from each other in the form of a dividend or loan. The guarantees rank (i) senior in right of payment to any future subordinated indebtedness of Gulfport Operating or the 2029 Senior Notes Guarantors, (ii) *pari passu* in right of payment with all existing and future unsecured senior indebtedness of Gulfport Operating or the 2029 Senior Notes Guarantors, (iii) effectively junior to any secured indebtedness of Gulfport Operating or the 2029 Senior Notes Guarantors, including indebtedness under the credit agreement, to the extent of the value of the collateral securing such indebtedness, and (iv) structurally subordinated in right of payment to all indebtedness and other liabilities of Gulfport Operating's subsidiaries that are not 2029 Senior Notes Guarantors.

SEC Regulation S-X Rule 13-01 requires the presentation of "Summarized Financial Information" to replace the "Condensed Consolidating Financial Information" required under Rule 3-10. Rule 13-01 allows the omission of Summarized Financial Information if assets, liabilities and results of operations of the Guarantors are not materially different than the corresponding amounts presented in our consolidated financial statements. The Parent and Guarantor subsidiaries comprise our material operations. Therefore, we concluded that the presentation of the Summarized Financial Information is not required as our Summarized Financial Information of the Guarantors is not materially different from our consolidated financial statements.

Derivatives and Hedging Activities. Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered 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 total revenue we will receive. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further discussion on the impact of commodity price risk on our financial position. Additionally, see Note 12 of our consolidated financial statements for further discussion of derivatives and hedging activities.

Subsequent to December 31, 2025 and as of February 19, 2026, we entered into the following natural gas, oil, and NGL derivative contracts:

Period	Type of Derivative Instrument	Index	Daily Volume	Weighted Average Price
Natural Gas			**(MMBtu/d)**	**($/MMBtu)**
2026	Swaps	NYMEX Henry Hub	36,603	$3.86
2027	Swaps	NYMEX Henry Hub	40,000	$3.80
2027	Basis Swaps	TETCO M2	50,000	$(0.80)
2027	Basis Swaps	Rex Zone 3	30,000	$(0.22)
2027	Basis Swaps	NGPL TXOK	30,000	$(0.34)
Oil			**(Bbl/d)**	**($/Bbl)**
2026	Costless Collars	NYMEX WTI	1,125	$55.00 / $71.18
2027	Costless Collars	NYMEX WTI	300	$55.00 / $68.00

Contractual and Commercial Obligations. The following table sets forth our contractual and commercial obligations at December 31, 2025 (in thousands):

	Payment due by period				
Contractual Obligations	Total	2026	2027-2028	2029-2030	2031 and Thereafter
Long-term debt[1]:					
Principal	$ 797,000	$ —	$ 147,000	$ 650,000	$ —
Interest	200,084	53,048	103,161	43,875	—
Firm transportation and gathering contracts[2]	1,037,663	138,975	269,992	253,586	375,110
Other operational commitments[3]	16,409	16,409	—	—	—
Operating lease liabilities[4]	571	561	10	—	—
Total contractual cash obligations[5]	$ 2,051,727	$ 208,993	$ 520,163	$ 947,461	$ 375,110

(1) The maturities of our debt obligations and associated interest reflect their original expiration dates and do not reflect any acceleration due to any events of default pertaining to these obligations. See Note 4 of our consolidated financial statements for a description of our long-term debt.
(2) See Note 17 of our consolidated financial statements for further discussion of our firm transportation and gathering commitments.
(3) See Note 17 of our consolidated financial statements for a description of our other operational commitments.
(4) See Note 9 of our consolidated financial statements for a description of our operating lease liabilities.
(5) This table does not include derivative liabilities or the estimated discounted cost for future abandonment of oil and natural gas properties. See Notes 12 and 3 of our consolidated financial statements, respectively.

Off-balance Sheet Arrangements. We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2025, our material off-balance sheet arrangements and transactions include $48.7 million in letters of credit outstanding against our Credit Facility and $45.3 million in surety bonds issued. Both the letters of credit and surety bonds are being used as financial assurance, primarily for certain firm transportation agreements. Additionally, the Company entered into various contractual commitments to purchase material and services to be used in future drilling and completion activities. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. See Note 17 of our consolidated financial statements for further discussion of the various financial guarantees we have issued.

Capital Expenditures. Our capital expenditures have historically been related to the execution of our drilling and completion activities in addition to certain lease acquisition activities. Our capital investment strategy is focused on prudently developing our existing properties to generate sustainable cash flow considering current and forecasted commodity prices. For the year ended December 31, 2025, the Company's incurred capital expenditures totaled $526.1 million related to operated activities, of which $428.4 million related to drilling and completion activities, $34.8 million related to maintenance leasehold and land investment and $62.9 million related to discretionary acreage acquisitions.

Our drilling and completion capital expenditures for 2026 are currently estimated to be in the range of $365 million to $390 million. Also, we currently expect to spend approximately $35 million to $40 million in 2026 for maintenance land and seismic investments, primarily focused on near-term drilling programs and facilitating increases in our working interests and lateral footage in units we plan to drill in 2026, 2027 and 2028. We expect this capital program to result in approximately 1.030 to 1.055 Bcfe per day of production in 2026.

Commodity Price Risk. The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. During 2025, WTI prices ranged from $55.44 to $80.73 per barrel and the Henry Hub spot market price of natural gas ranged from $2.65 to $9.86 per MMBtu. During 2024, WTI prices ranged from $66.73 to $87.69 per barrel and the Henry Hub spot market price of natural gas ranged from $1.21 to $13.20 per MMBtu. If the prices of oil and natural gas continue to be volatile, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in commodity prices and/or our reserves could also negatively impact the borrowing base under our revolving credit facility, which could limit our liquidity and ability to fund development activities.

See Item 7A. “Quantitative and Qualitative Disclosures about Market Risk” for further information regarding our open derivative instruments at December 31, 2025.

Sources and Uses of Cash

The following table presents the major changes in cash and cash equivalents for the year ended December 31, 2025 and 2024 (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024
Net cash provided by operating activities	$ 803,193	$ 650,033
Additions to oil and natural gas properties	(527,569)	(454,098)
Debt activity, net	83,298	32,761
Debt issuance and loan commitment fees	(35)	(14,933)
Repurchases of common stock	(304,961)	(184,477)
Redemption of preferred stock	(32,423)	—
Net cash payments on performance vesting restricted stock units	(12,297)	—
Dividends on preferred stock	(1,666)	(4,230)
Shares exchanged for tax withholdings	(5,579)	(23,614)
Other	(1,621)	(1,898)
Net change in cash and cash equivalents	$ 340	$ (456)
Cash and cash equivalents at end of period	$ 1,813	$ 1,473

Net cash provided by operating activities. Net cash provided by operating activities was $803.2 million for the year ended December 31, 2025, compared to $650.0 million for the year ended December 31, 2024. The increase was primarily the result of a increase in our natural gas revenues.

Additions to oil and natural gas properties. During the year ended December 31, 2025, we spud 24 gross (23.9 net) operated wells and commenced sales from 30 gross (30.0 net) operated wells targeting the Utica and Marcellus formations for a total cost incurred of approximately $401.0 million. During the year ended December 31, 2025, we did not spud any operated wells and commenced sales from 2 gross (1.8 net) operated wells in the SCOOP for a total incurred cost of approximately $27.5 million. Additionally, the Company incurred $34.8 million related to maintenance leasehold and land investment and $62.9 million related to discretionary acreage acquisitions.

Drilling and completion costs discussed above reflect incurred costs while drilling and completion costs presented in the table below reflect cash payments for drilling and completions. Incurred capital expenditures and cash capital expenditures may vary from period to period due to the cash payment cycle. Cash capital expenditures for the year ended December 31, 2025 and 2024, were as follows (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024
Oil and Natural Gas Property Cash Expenditures:		
Drilling and completion costs	$ 404,239	$ 325,129
Leasehold acquisitions	95,610	102,630
Other	27,720	26,339
Total oil and natural gas property expenditures	$ 527,569	$ 454,098

Debt activity, net. During the year ended December 31, 2025, the Company had $1.4 billion and $1.2 billion in borrowings and repayments, respectively, on its Credit Facility. In May 2025, the Company redeemed the remaining $25.7 million principal amount of its 2026 Senior Notes at par. As of February 19, 2026, the Company had $219.0 million in borrowings outstanding on its Credit Facility.

Debt issuance and loan commitment fees. During the year ended December 31, 2024, the Company incurred $14.9 million of debt issuance and loan commitment fees, related to the issuance of the 2029 Senior Notes and the Fourth Amendment to the Credit Facility. See Note 4 of our consolidated financial statements for further discussion of the long-term debt activity.

Repurchases of common stock. During the year ended December 31, 2025, the Company repurchased 1.8 million shares for approximately $336.3 million under the Repurchase Program at a weighted average price of $188.65 per share. For the same period in 2024, the Company repurchased 1.2 million shares for $184.5 million at a weighted average price of $153.35 per share.

Redemption of preferred stock. On August 5, 2025, Gulfport issued a notice of redemption for its preferred stock for cash. During the period between the date of the notice of redemption and the Redemption Date, 28,907 shares of preferred stock were converted into approximately 2.1 million shares of common stock. On the Redemption Date, the Company redeemed the remaining 2,449 shares of preferred stock for cash totaling $31.3 million. Additionally, direct transaction-related costs of $1.1 million were incurred as part of the redemption. See Note 5 of our consolidated financial statements for further discussion of the redemption of preferred stock.

Net cash payments on performance vesting restricted stock units. During the year ended December 31, 2025, the Company settled certain performance vesting restricted stock units awards that were granted in 2022 in cash for $12.3 million, as discussed in Note 7 of our consolidated financial statements.

Dividends on preferred stock. During the year ended December 31, 2025, the Company paid $1.7 million of cash dividends to holders of our preferred stock compared to $4.2 million in the year ended December 31, 2024. No cash dividends were paid after the Redemption Date.

Shares exchanged for tax withholdings. During the year ended December 31, 2025, the Company paid $5.6 million of shares exchanged for tax withholdings compared to $23.6 million in the year ended December 31, 2024. The decrease was primarily due to lower aggregate fair value of vested awards as discussed in Note 7 of our consolidated financial statements.

Critical Accounting Policies and 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 we consider to be most significant to our financial statements are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized.

Under the full cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

We review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test.

Two primary factors impacting this test are reserve estimates and the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2025. Downward revisions to estimates of oil and natural gas reserves and/or unfavorable prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. The Company did not record an impairment of its oil and natural gas properties for the year ended December 31, 2025 and recognized ceiling test impairments of $373.2 million during 2024. See Oil and Natural Gas Properties in Note 1 of our consolidated financial statements for further information on the full cost method of accounting.

Oil, Natural Gas and NGL Reserves. Estimates of oil and natural gas 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 Note 20 of our consolidated financial statements for further information.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. At each reporting period, the Company weighs all available positive and negative evidence to determine whether its deferred tax assets are more likely than not to be realized. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. To assess that likelihood, the Company uses estimates and judgment regarding future taxable income and considers the tax laws in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, results of operations, both actual and forecasted, the reversal of deferred tax liabilities and tax planning strategies as well as the current and forecasted business economics of the oil and gas industry. Based upon the Company’s analysis, the Company currently believes that it is more likely than not that a portion of the Company's federal and state deferred tax assets will be utilized.

Revenue Recognition. We derive almost all of our revenue from the sale of natural gas, crude oil and NGL produced from our oil and natural gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. Historically, our actual payments received have not significantly deviated from our accruals.

Derivative Instruments. We seek to reduce our exposure to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, costless collars and various types of option contracts. All derivative instruments are recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Our current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Natural Gas, Oil and Natural Gas Liquids Derivative Instruments. Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered 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.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas, oil and NGL futures markets when prices reach levels that management believes provide reasonable risk-adjusted rates of return and protect the financial position of the Company. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends. Executive management is involved in all risk management activities and the Board of Directors reviews our derivative program at its quarterly board meetings.

We use derivative instruments to achieve our risk management objectives, including swaps, options and costless collars. All of these are described in more detail below. We typically use swaps for a large portion of the oil and natural gas price risk we hedge. We have also sold calls in the past to take advantage of premiums associated with market price volatility.

We determine the notional volume potentially subject to derivative contracts by reviewing our overall estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of estimated production from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not enter into derivative contracts for volumes in excess of our share of forecasted production. The actual fixed prices on our derivative instruments is derived from the reference prices from third-party indices such as NYMEX. All of our commodity derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating price, resulting in a net amount due to or from the counterparty.

We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we mitigate this risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering a new trade that effectively reverses the current position. The factors we consider in closing or restructuring a position before the settlement date are consistent with those we review when deciding to enter the original derivative position.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves, discount factors and option pricing models. 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. 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 our consolidated financial statements for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2025, our natural gas, oil and NGL 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.
- *Basis 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.
- *Costless Collars*: Each two-way price collar has a set floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, the Company will cash-settle the difference with the counterparty.

Our hedge arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or commodity prices increase. At December 31, 2025, we had a net asset derivative position of $29.7 million, compared to a net liability derivative position of $12.9 million as of December 31, 2024. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have decreased our asset by approximately $80.9 million, while a 10% decrease in underlying commodity prices would have increased our asset by approximately $80.9 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument. For more information regarding the Company's commodity derivative transactions, refer to Note 12 of our consolidated financial statements.

Counterparty Credit Risk. The Company routinely monitors and manages its exposure to counterparty risk related to derivative contracts by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties public credit ratings, and avoiding concentration of credit exposure by transacting with multiple counterparties. The Company's commodity derivative contract counterparties are typically financial institutions with investment-grade credit ratings. The Company enters into International Swap Dealers Association Master Agreements (“ISDA”) with each of its derivative counterparties prior to executing derivative contracts. The terms of the ISDA provide, among other things, the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or counterparty to a derivative contract.

Interest Rate Risk. Our Credit Facility is structured under floating rate terms, as advances under these facilities may be in the form of either base rate loans or term benchmark loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the United States or, if the term benchmark rates are elected, the term benchmark rates. At December 31, 2025, we had $147.0 million in borrowings outstanding under our Credit Facility which bore interest at the weighted average rate of 6.53% for the year ended December 31, 2025. A 1% increase in the average interest rate would increase interest expense by approximately $1.5 million based on outstanding borrowings under our Credit Facility at December 31, 2025. As of December 31, 2025, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 25, 2026 expressed an unqualified opinion.

Basis for opinion

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

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

Critical audit matter

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

Depreciation, depletion and amortization expense and potential impairment of oil and natural gas properties impacted by the Company's estimation of proved reserves

As described further in Note 1 and Note 3 to the consolidated financial statements, the Company uses the full cost method of accounting for oil and natural gas properties. This accounting method requires management to make estimates of proved reserves and related future net cash flows to compute and record depreciation, depletion, and amortization, as well as to assess potential impairment of oil and natural gas properties (the full cost ceiling test). To estimate the volume of proved oil and natural gas reserve quantities, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with those proved reserves to determine if wells are expected to be economical under the appropriate pricing assumptions that are required in the estimation of proved reserves. We

identified the estimation of proved reserves as it relates to the recognition of depreciation, depletion, and amortization expense and the assessment of potential impairment as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter in that relatively minor changes in certain inputs and assumptions that are necessary to estimate the volume and future cash flows of the Company's proved reserves could have a significant impact on the measurement of depreciation, depletion, and amortization expense and the assessment of potential impairment. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- Tested the design and operating effectiveness of internal controls relating to management's estimation of proved reserves for the purpose of estimating depreciation, depletion, and amortization expense and assessment of potential impairment for the Company's oil and natural gas properties.
- Evaluated the independence, objectivity and professional qualifications of the specialists, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes and read the report prepared by the Company's third-party reserve specialist.
- Evaluated significant inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions, such as historical production, historical pricing differentials, operating costs, estimated future development cost, and ownership interest for reasonableness. We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis where applicable. Specifically, our audit procedures involved testing management's assumptions as follows:
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year;
    - Tested the estimate of operating costs on a disaggregated basis at year-end and compared to historical operating costs;
    - Tested the model used to determine the future development costs and compared and estimated future development costs used in the reserve report to amounts expended for recently drilled and completed wells, where applicable;
    - Tested the working and net revenue interest used in the reserve report by inspecting land and division order records;
    - Assessed forecasted production estimated by (i) comparing prior year forecasted production amounts to current year actual results and (ii) comparing forecasted production amounts in the current year reserve report to the actual historical production amounts in the current year, in total and for a sample of individual wells;
    - Evaluated the Company's evidence supporting the proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year's reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2005.

Oklahoma City, Oklahoma
February 25, 2026

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2025	December 31, 2024
Assets		
Current assets:		
Cash and cash equivalents	$ 1,813	$ 1,473
Accounts receivable—oil, natural gas, and natural gas liquids sales	184,649	155,942
Accounts receivable—joint interest and other	9,282	8,727
Prepaid expenses and other current assets	7,952	7,086
Short-term derivative instruments	45,155	58,085
Total current assets	248,851	231,313
Property and equipment:		
Oil and natural gas properties, full-cost method		
Proved oil and natural gas properties	3,902,539	3,349,805
Unproved properties	232,959	221,650
Other property and equipment	13,008	11,291
Total property and equipment	4,148,506	3,582,746
Less: accumulated depletion, depreciation, amortization and impairment	(1,868,481)	(1,564,475)
Total property and equipment, net	2,280,025	2,018,271
Other assets:		
Long-term derivative instruments	15,303	6,003
Deferred tax asset	465,738	581,233
Operating lease assets	561	6,099
Other assets	19,062	22,778
Total other assets	500,664	616,113
Total assets	$ 3,029,540	$ 2,865,697
Liabilities, Mezzanine Equity and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 342,382	$ 298,081
Short-term derivative instruments	21,865	41,889
Current portion of operating lease liabilities	550	5,538
Total current liabilities	364,797	345,508
Non-current liabilities:		
Long-term derivative instruments	8,916	35,081
Asset retirement obligation	32,912	32,949
Non-current operating lease liabilities	10	561
Long-term debt	788,187	702,857
Total non-current liabilities	830,025	771,448
Total liabilities	1,194,822	1,116,956
Commitments and contingencies (Notes 17 and 18)		
Mezzanine equity:		
Preferred stock - $0.0001 par value, 110.0 thousand shares authorized, 0 issued and outstanding at December 31, 2025, and 37.3 thousand issued and outstanding at December 31, 2024	—	37,348
Stockholders' equity:		
Common stock - $0.0001 par value, 42.0 million shares authorized, 18.8 million issued and outstanding at December 31, 2025, and 17.8 million issued and outstanding at December 31, 2024	2	2
Additional paid-in capital	—	129,059
Retained earnings	1,834,716	1,582,332
Total stockholders' equity	1,834,718	1,711,393
Total liabilities, mezzanine equity and stockholders' equity	$ 3,029,540	$ 2,865,697

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
REVENUES:			
Natural gas sales	$ 1,056,429	$ 714,160	$ 831,812
Oil and condensate sales	133,644	101,589	99,854
Natural gas liquid sales	133,454	112,855	119,717
Net gain on natural gas, oil and NGL derivatives	99,056	29,527	740,319
Total revenues	1,422,583	958,131	1,791,702
OPERATING EXPENSES:			
Lease operating expenses	84,242	70,112	68,648
Taxes other than income	29,908	29,737	33,717
Transportation, gathering, processing and compression	358,938	351,237	348,631
Depreciation, depletion and amortization	304,162	325,723	319,715
Impairment of oil and natural gas properties	—	373,214	—
General and administrative expenses	42,488	42,558	38,600
Restructuring costs	—	—	4,762
Accretion expense	2,421	2,307	2,782
Total operating expenses	822,159	1,194,888	816,855
INCOME (LOSS) FROM OPERATIONS	600,424	(236,757)	974,847
OTHER EXPENSE (INCOME):			
Interest expense	54,277	59,982	57,069
Loss on debt extinguishment	—	13,388	—
Other, net	2,842	7,336	(27,982)
Total other expense	57,119	80,706	29,087
INCOME (LOSS) BEFORE INCOME TAXES	543,305	(317,463)	945,760
INCOME TAX EXPENSE (BENEFIT):			
Current	—	—	—
Deferred	115,495	(56,077)	(525,156)
Total income tax expense (benefit)	115,495	(56,077)	(525,156)
NET INCOME (LOSS)	427,810	(261,386)	1,470,916
Dividends on preferred stock	(1,666)	(4,230)	(4,840)
Deemed dividend on preferred stock	(29,986)	—	—
Participating securities - preferred stock	—	—	(212,360)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ 396,158	$ (265,616)	$ 1,253,716
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 21.74	$ (14.72)	$ 67.24
Diluted	$ 21.48	$ (14.72)	$ 66.46
Weighted average common shares outstanding—Basic	18,223	18,050	18,645
Weighted average common shares outstanding—Diluted	18,440	18,050	18,902

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Common Stock		Common Stock Held in Reserve		Treasury Stock	Paid-in Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance at January 1, 2023	19,097	$ 2	(62)	$ (1,996)	$ (286)	$ 449,243	$ 381,872	828,835
Net income	—	—	—	—	—	—	1,470,916	1,470,916
Conversion of preferred stock	593	—	—	—	—	8,081	—	8,081
Stock compensation	—	—	—	—	—	13,525	—	13,525
Repurchase of common stock under Repurchase Program	(1,470)	—	—	—	286	(151,912)	—	(151,626)
Issuance of common stock upon vesting of share-based awards	102	—	—	—	—	—	—	—
Common stock withheld for income taxes on share-based awards	(34)	—	—	—	—	(3,207)	—	(3,207)
Dividends on preferred stock	—	—	—	—	—	(4)	(4,840)	(4,844)
Balance at December 31, 2023	18,288	$ 2	(62)	$ (1,996)	$ —	$ 315,726	$ 1,847,948	$ 2,161,680
Net loss	—	—	—	—	—	—	(261,386)	(261,386)
Conversion of preferred stock	500	—	—	—	—	6,866	—	6,866
Stock compensation	—	—	—	—	—	16,355	—	16,355
Repurchase of common stock under Repurchase Program	(1,203)	—	—	—	—	(186,271)	—	(186,271)
Issuance of common stock held in reserve	—	—	62	1,996	—	—	—	1,996
Issuance of common stock upon vesting of share-based awards	363	—	—	—	—	—	—	—
Common stock withheld for income taxes on share-based awards	(150)	—	—	—	—	(23,614)	—	(23,614)
Dividends on preferred stock	—	—	—	—	—	(3)	(4,230)	(4,233)
Balance at December 31, 2024	17,798	$ 2	—	$ —	$ —	$ 129,059	$ 1,582,332	$ 1,711,393
Net income	—	—	—	—	—	—	427,810	427,810
Conversion of preferred stock	2,555	—	—	—	—	34,899	—	34,899
Redemption of preferred stock	—	—	—	—	—	—	(29,986)	(29,986)
Stock compensation	—	—	—	—	—	18,143	—	18,143
Net cash payments on performance vesting restricted stock units	—	—	—	—	—	(12,297)	—	(12,297)
Repurchase of common stock under Repurchase Program	(1,603)	—	—	—	—	(164,216)	(143,774)	(307,990)
Issuance of common stock upon vesting of share-based awards	91	—	—	—	—	—	—	—
Common stock withheld for income taxes on share-based awards	(31)	—	—	—	—	(5,579)	—	(5,579)
Dividends on preferred stock	—	—	—	—	—	(9)	(1,666)	(1,675)
Balance at December 31, 2025	18,810	$ 2	—	$ —	$ —	$ —	$ 1,834,716	$ 1,834,718

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Cash flows from operating activities:			
Net income (loss)	$ 427,810	$ (261,386)	$ 1,470,916
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	304,162	325,723	319,715
Impairment of oil and natural gas properties	—	373,214	—
Loss on debt extinguishment	—	13,388	—
Net gain on derivative instruments	(99,056)	(29,527)	(740,319)
Net cash receipts on settled derivative instruments	56,497	282,637	152,199
Deferred income tax expense (benefit)	115,495	(56,077)	(525,156)
Stock-based compensation expense	12,156	10,958	9,480
Other, net	8,599	6,315	7,645
Changes in operating assets and liabilities, net	(22,470)	(15,212)	28,701
Net cash provided by operating activities	803,193	650,033	723,181
Cash flows from investing activities:			
Additions to oil and natural gas properties	(527,569)	(454,098)	(537,360)
Proceeds from sale of oil and natural gas properties	150	225	2,659
Other, net	(1,762)	(2,120)	(2,526)
Net cash used in investing activities	(529,181)	(455,993)	(537,227)
Cash flows from financing activities:			
Principal payments on Credit Facility	(1,246,000)	(1,036,000)	(998,000)
Borrowings on Credit Facility	1,355,000	956,000	971,000
Issuance of 2029 Senior Notes	—	650,000	—
Early retirement of 2026 Senior Notes	(25,702)	(524,298)	—
Premium paid on 2026 Senior Notes	—	(12,941)	—
Debt issuance costs and loan commitment fees	(35)	(14,933)	(7,068)
Dividends on preferred stock	(1,666)	(4,230)	(4,840)
Redemption of preferred stock	(32,423)	—	—
Repurchase of common stock under Repurchase Program	(279,961)	(105,344)	(108,735)
Repurchase of common stock under Repurchase Program - related party	(25,000)	(79,133)	(40,430)
Net cash payments on performance vesting restricted stock units	(12,297)	—	—
Shares exchanged for tax withholdings	(5,579)	(23,614)	(3,207)
Other, net	(9)	(3)	(4)
Net cash used in financing activities	(273,672)	(194,496)	(191,284)
Net change in cash and cash equivalents	340	(456)	(5,330)
Cash and cash equivalents at beginning of period	1,473	1,929	7,259
Cash and cash equivalents at end of period	$ 1,813	$ 1,473	$ 1,929

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Company

Gulfport Energy Corporation is an independent natural gas-weighted exploration and production company focused on the exploration, acquisition and production of natural gas, crude oil and NGL in the United States with primary focus in the Appalachia and Anadarko basins. The Company's principal properties are located in eastern Ohio targeting the Utica and Marcellus and in central Oklahoma targeting the SCOOP Woodford and Springer formations.

Basis of Presentation

The consolidated financial statements included in this Annual Report are prepared in accordance with GAAP and the rules and regulations of the SEC.

Risks and Uncertainties

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil, gas and NGL, which are affected by many factors outside of Gulfport's control, including changes in market supply and demand. Field-level prices received for Gulfport's production have historically been volatile and may be subject to significant fluctuations in the future. The Company's derivative contracts serve to mitigate in part the effect of this price volatility on the Company's cash flows, and the Company has derivative contracts in place for a portion of its expected future natural gas, crude oil and NGL production. See Note 12 for further discussion of the Company's commodity derivative contracts.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly-owned subsidiaries, Gulfport Energy Operating Corporation, Gulfport Appalachia LLC, Gulfport MidCon LLC, Puma Resources Inc., Westhawk Minerals LLC, Grizzly Holdings Inc., Mule Sky LLC and Gulfport LA Inc. All intercompany balances and transactions are eliminated in consolidation.

Segments

The Company's assets and operations consist of one reportable segment. The Company has a single management team that administers all properties as a whole rather than by geographic operating area. See Note 2, Segment Information, for further detail.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the consolidated financial statements.

Accounts Receivable

The Company sells oil and natural gas to various purchasers and participates in drilling, completion and operation of oil and natural gas wells with joint interest owners on properties the Company operates. The related receivables are classified as accounts receivable—oil and natural gas sales and accounts receivable—joint interest and other, respectively. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. No material allowance was deemed necessary at December 31, 2025 and December 31, 2024.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Additionally, interest is capitalized on the cost of unproved oil and natural gas properties that are excluded from amortization for which exploration and development activities are in process or expected within the next 12 to 18 months.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue (only to the extent that the derivative instruments are treated as cash flow hedges for accounting purposes), and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of unproved properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash write-down is required. Ceiling test impairment can result in a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. There were no impairments recognized in 2025 and 2023. The Company recognized ceiling test impairments of $373.2 million during 2024.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties, are depleted by an equivalent units-of-production method, converting oil and NGL barrels to gas equivalents at the ratio of one barrel to six Mcf of gas. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proved oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled approximately $233.0 million and $221.7 million at December 31, 2025 and December 31, 2024, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities by recording a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Depreciation of other property and equipment is provided on a straight-line basis over the estimated useful lives of the related assets, which range from 2 to 30 years.

Net Income (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income (loss) per common share are illustrated in Note 11.

Income Taxes

The amount of income taxes recorded by Gulfport requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2022. As of December 31, 2025, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. See Note 10 for further discussion of the Company's income taxes.

Revenue Recognition

The Company’s revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company’s right to payment and (iv) transfer of legal title.

Gathering, processing and compression fees attributable to gas processing, as well as any transportation fees, including firm transportation fees, incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing and compression in the accompanying consolidated statements of operations.

Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

The recognition of gains or losses on derivative instruments is outside the scope of ASC 606, *Revenue from Contracts with Customers* and is not considered revenue from contracts with customers subject to ASC 606. The Company may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales, or in limited cases may use them for contracts the Company intends to physically settle but do not meet all of the criteria to be treated as normal sales.

The Company has elected to exclude from the measurement of the transaction price all taxes assessed by governmental authorities that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Company from a customer, such as sales tax, use tax, value-added tax and similar taxes.

See Note 8 for additional discussion of revenue from contracts with customers.

Accounting for Stock-based Compensation

Share-based payments to employees and members of its Board of Directors, including grants of restricted stock units and performance vesting restricted stock units, are recognized as equity at the fair value on the date of grant and to be expensed over the applicable vesting period. The vesting periods for restricted shares generally range between one year to three years with annual vesting installments. The Company does not recognize expense based on an estimate of forfeitures, but rather recognizes the impact of forfeitures only as they occur.

Derivative Instruments

The Company utilizes commodity derivatives to manage the price risk associated with forecasted sale of its natural gas, crude oil and NGL production. All derivative instruments are recognized as assets or liabilities in the consolidated balance sheets, measured at fair value. The Company does not apply hedge accounting to derivative instruments. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets, the fair value determination of acquired assets and liabilities and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company's oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Reclassification

Certain reclassifications have been made to prior period financial statements and related disclosures to conform to current period presentation. These reclassifications have no impact on previous reported total assets, total liabilities, net income (loss) or total operating cash flows.

Supplemental Cash Flow and Non-Cash Information (in thousands)

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Supplemental disclosure of cash flow information:			
Interest payments, net of amounts capitalized	$ 47,758	$ 46,406	$ 53,820
Cash payments (income taxes)			
Federal taxes	$ 1,200	$ —	$ —
State taxes	$ —	$ —	$ —
Changes in operating assets and liabilities, net:			
Accounts receivable - oil, natural gas, and natural gas liquids sales	$ (28,707)	$ (33,463)	$ 155,925
Accounts receivable - joint interest and other	(555)	13,494	(743)
Accounts payable and accrued liabilities	8,193	4,067	(126,329)
Prepaid expenses	(1,412)	667	(215)
Other assets	11	23	63
Total changes in operating assets and liabilities, net	$ (22,470)	$ (15,212)	$ 28,701
Supplemental disclosure of non-cash transactions:			
Capitalized stock-based compensation	$ 5,987	$ 5,397	$ 4,046
Asset retirement obligation capitalized	$ 559	$ 682	$ 588
Asset retirement obligation removed due to divestiture and settlements	$ (1,587)	$ —	$ (1,267)
Asset retirement obligation revisions	$ 9	$ 19	$ (5,077)
Release of common stock held in reserve	$ —	$ 1,996	$ —
Unamortized 2026 Senior Notes debt issuance costs	$ —	$ 447	$ —

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities consisted of the following (in thousands):

	December 31, 2025	December 31, 2024
Revenue payable and suspense	$ 157,532	$ 139,703
Accounts payable	53,107	34,668
Accrued transportation, gathering, processing, and compression	38,544	36,170
Accrued capital expenditures	30,873	20,229
Other accrued liabilities	62,326	67,311
Total accounts payable and accrued liabilities	$ 342,382	$ 298,081

Recent Accounting Pronouncements

In December 2023, the FASB issued ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures (Topic 740). The amendment requires annual disclosure of additional categories of information about federal, state, and foreign income taxes in the rate reconciliation table and to provide more details about the reconciling items in some categories if the items meet a quantitative threshold. Additionally, the amendment requires disclosure of annual income taxes paid (net of refunds received) disaggregated by federal, state, and foreign taxes and to disaggregate the information by jurisdiction based on a quantitative threshold. The Company retrospectively adopted ASU 2023-09 during the year ended December 31, 2025. See Note 10, Income Taxes, for further detail.

In November 2024, the FASB issued ASU 2024-03, Disaggregation of Income Statement Expenses, which requires disclosures about specific types of expenses included in the expense captions presented on the face of the income statement as well as disclosures about selling expenses. ASU 2024-03 is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. The requirements will be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact that the adoption of this accounting standard will have on its financial disclosures.

2. SEGMENT INFORMATION

The Company's assets and operations consist of one reportable segment with all revenues, operating expenses and assets attributable to this segment reflected in the consolidated financial statements. The Company derives its revenue from the sale of natural gas, oil and condensate and NGL produced from its oil and natural gas properties located in the United States.

The CODM of the Company is its Chief Executive Officer. The CODM assesses entity-wide operating results and performance and decides how to allocate resources based on net income (loss), which is reported on the consolidated statement of operations.

The measure of segment assets is reported on the consolidated balance sheets as “total assets”.

The following table presents selected financial information with respect to the Company's one operating segment for the years ended December 31, 2025, 2024 and 2023 (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Total revenues	$ 1,422,583	$ 958,131	$ 1,791,702
Significant segment expenses:			
Lease operating expenses	84,242	70,112	68,648
Taxes other than income	29,908	29,737	33,717
Transportation, gathering, processing and compression	358,938	351,237	348,631
Depreciation, depletion, and amortization	304,162	325,723	319,715
Impairment of oil and gas properties	—	373,214	—
General and administrative	42,488	42,558	38,600
Interest expense	54,277	59,982	57,069
Other segment expenses[1]	5,263	23,031	(20,438)
Income tax expense (benefit)	115,495	(56,077)	(525,156)
Total significant segment expenses	994,773	1,219,517	320,786
Net income (loss)	$ 427,810	$ (261,386)	$ 1,470,916
Capital expenditures[2]	$ 565,273	$ 464,492	$ 521,187

(1) Other segment expenses include "Restructuring costs", "Accretion expense", "Loss on debt extinguishment" and "Other, net" from the consolidated statements of operations.
(2) Capital expenditures include capitalized general and administrative costs and capitalized interest expense.

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated DD&A are as follows (in thousands):

	December 31, 2025	December 31, 2024
Proved oil and natural gas properties	$ 3,902,539	$ 3,349,805
Unproved properties	232,959	221,650
Other depreciable property and equipment	12,622	10,905
Land	386	386
Total property and equipment	4,148,506	3,582,746
Accumulated DD&A and impairment	(1,868,481)	(1,564,475)
Property and equipment, net	$ 2,280,025	$ 2,018,271

Oil and Natural Gas Properties

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the Company's oil and natural gas properties. At December 31, 2025, the net book value of the Company's oil and gas properties was below the calculated ceiling. As a result, the Company did not record an impairment of its oil and natural gas properties for the year ended December 31, 2025. During the year ended December 31, 2024, the net book value of the Company's oil and gas properties exceeded the calculated ceiling. As a result, the Company recorded a non-cash ceiling test impairment of its oil and natural gas properties of $30.5 million in the third quarter of 2024 and $342.7 million in the fourth quarter of 2024. The impairments resulted from declines in the full cost ceiling, which primarily resulted from the significant decrease in the 12-month average trailing price for natural gas. The Company did not record an impairment of its oil and natural gas properties during 2023.

General and administrative costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $25.2 million, $25.3 million and $22.8 million for the years ended December 31, 2025, 2024 and 2023, respectively. The average depletion rate per Mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $0.80, $0.84 and $0.83 per Mcfe for the years ended December 31, 2025, 2024 and 2023, respectively.

The following table summarizes the Company's non-producing properties excluded from amortization by area (in thousands):

	December 31, 2025	December 31, 2024
Utica & Marcellus	$ 210,185	$ 197,513
SCOOP	22,774	24,137
Total unproved properties	$ 232,959	$ 221,650

The following is a summary of Gulfport's oil and natural gas properties not subject to amortization as of December 31, 2025 (in thousands):

	Costs Incurred in				
	2025	2024	2023	Prior to 2023	Total
Acquisition costs	$ 65,239	$ 58,722	$ 58,002	$ 41,715	$ 223,678
Exploration costs	—	—	—	—	—
Development costs	3,820	1,246	418	—	5,484
Capitalized interest	3,612	185	—	—	3,797
Total oil and natural gas properties not subject to amortization	$ 72,671	$ 60,153	$ 58,420	$ 41,715	$ 232,959

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company's activities, the inclusion of most of the above referenced costs into the Company's amortization calculation typically occurs within three years to five years. However, the majority of the Company's non-producing leases in the Utica/Marcellus have five-year extension terms, which could extend this time frame beyond five years.

Asset Retirement Obligation

The following table provides a reconciliation of the Company's asset retirement obligation for the years ended December 31, 2025 and 2024 (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024
Asset retirement obligation, beginning of period	$ 32,949	$ 29,941
Liabilities incurred	559	682
Liabilities settled	(3,026)	—
Accretion expense	2,421	2,307
Revisions in estimated cash flows[1]	9	19
Asset retirement obligation, end of period	$ 32,912	$ 32,949

(1) Revisions represent changes in the present value of liabilities resulting from changes in estimated costs.

4. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31, 2025 and 2024 (in thousands):

	December 31, 2025	December 31, 2024
6.75% senior unsecured notes due 2029	$ 650,000	$ 650,000
8.00% senior unsecured notes due 2026	—	25,702
Credit Facility due 2028	147,000	38,000
Net unamortized debt issuance costs	(8,813)	(10,845)
Total debt, net	788,187	702,857
Less: current maturities of long-term debt	—	—
Total long-term debt, net	$ 788,187	$ 702,857

Senior Notes

In September 2024, Gulfport Operating completed a private offering of $650.0 million aggregate principal amount of 6.75% senior notes due September 1, 2029. The 2029 Senior Notes are guaranteed on a senior unsecured basis by the Company and each of the Company's subsidiaries that guarantee the Credit Facility. Interest is payable semi-annually, on March 1 and September 1 of each year, beginning on March 1, 2025.

The 2029 Senior Notes were issued under the 2029 Senior Notes Indenture, dated as of September 13, 2024, by and among Gulfport Operating, UMB Bank, National Association, as trustee, and the Guarantors.

The 2029 Senior Notes Indenture contains covenants limiting Gulfport Operating's and its restricted subsidiaries' ability to incur additional indebtedness, make restricted payments, and engage in certain other transactions, subject to exceptions and qualifications. Certain covenants will be suspended if the 2029 Senior Notes achieve investment grade ratings.

The net proceeds from the 2029 Senior Notes offering, together with cash on hand were used to purchase and retire $524.3 million of its 2026 Senior Notes in a tender offer and to repay a portion of the Company's outstanding borrowings under the Credit Facility. The tender offer resulted in a $13.4 million loss on debt extinguishment. In May 2025, the Company redeemed the remaining balance of its 2026 Senior Notes, at par for $25.7 million. No additional fees or penalties were incurred as a result of the early redemption.

Credit Facility

The Company maintains a senior secured reserve-based revolving credit facility under its Third Amended and Restated Credit Agreement, as amended most recently by the Borrowing Base Reaffirmation Agreement and Fifth Amendment to Credit Agreement (the "Fifth Amendment") dated October 30, 2025. The facility provides for a borrowing base of $1.1 billion and aggregate elected commitments of $1.0 billion. The facility matures on September 12, 2028, is secured by substantially all of the Company's assets and is guaranteed by the Company's material domestic subsidiaries. Borrowings under the facility bear interest, at the Company's election, at a rate equal to either the SOFR benchmark plus an applicable margin ranging from 2.25% to 3.25% per annum or a base rate plus an applicable margin ranging from 1.25% to 2.25% per annum, in each case based on borrowing base utilization. The Company also pays a commitment fee ranging from 0.375% to 0.50% per annum on the average daily unused portion of the elected commitments. The credit agreement contains customary affirmative and negative covenants, including financial covenants requiring the Company to maintain a net funded leverage ratio of not more than 3.50 to 1.00 and a current ratio of at least 1.00 to 1.00, measured as of the last day of each fiscal quarter.

As of December 31, 2025, the Company had $147.0 million outstanding borrowings under the Credit Facility, $48.7 million in letters of credit outstanding and was in compliance with all covenants under the credit agreement.

For the years ended December 31, 2025 and 2024, the Credit Facility bore interest at a weighted average rate of 6.53% and 8.23%, respectively.

Interest Expense

The following schedule shows the components of interest expense for the years ended December 31, 2025, 2024 and 2023 (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Cash paid for interest	$ 53,913	$ 51,177	$ 57,967
Change in accrued interest	1,260	9,368	(7)
Capitalized interest	(6,154)	(4,771)	(4,147)
Amortization of loan costs	5,258	4,208	3,256
Other	—	—	—
Total interest expense	$ 54,277	$ 59,982	$ 57,069

The Company capitalized $6.2 million, $4.8 million and $4.1 million in interest expense for the years ended December 31, 2025, 2024 and 2023, respectively, to undeveloped oil and natural gas properties.

Fair Value of Debt

At December 31, 2025, the carrying value of the outstanding debt represented by the 2029 Senior Notes was approximately $641.2 million. Based on the quoted market prices (Level 1), the fair value of the 2029 Senior Notes was determined to be approximately $672.3 million at December 31, 2025.

5. MEZZANINE EQUITY

The Company's amended and restated certificate of incorporation provides for, among other things, (i) the authority to issue 42 million shares of common stock with a par value of $0.0001 per share and (ii) the designation of 110,000 shares of preferred stock, with a par value of $0.0001 per share and a liquidation preference of $1,000 per share (the “Liquidation Preference”).

Preferred Stock

In May 2021, the Company issued 55,000 shares of Series A Convertible Preferred Stock ("preferred stock").

Prior to the redemption of the preferred stock noted below, holders of preferred stock were entitled to receive cumulative quarterly dividends at a rate of 10% per annum of the Liquidation Preference with respect to cash dividends and 15% per annum of the Liquidation Preference with respect to dividends paid in kind as additional shares of preferred stock (“PIK Dividends”). Gulfport had the option to pay either cash dividends or PIK Dividends on a quarterly basis.

Each holder of shares of preferred stock had the right (the “Conversion Right”), at its option and at any time, to convert all or a portion of the shares of preferred stock that it holds into a number of shares of common stock equal to the quotient obtained by dividing (x) the product obtained by multiplying (i) the Liquidation Preference times (ii) an amount equal to one (1) plus the Per Share Makewhole Amount (as defined in the Preferred Terms) on the date of conversion, by (y) $14.00 per share (as may be adjusted under the Preferred Terms).

The preferred stock had no stated maturity and would remain outstanding indefinitely unless repurchased or redeemed by Gulfport or converted into common stock. The preferred stock was classified as mezzanine equity in the accompanying consolidated balance sheets due to the redemption features.

Redemption of Preferred Stock

On August 5, 2025, Gulfport issued a notice of redemption for its preferred stock for cash. During the period between the date of the notice of redemption and September 5, 2025 (the "Redemption Date"), 28,907 shares of preferred stock were converted into approximately 2.1 million shares of common stock and reclassified from mezzanine equity to stockholders' equity. On the Redemption Date, the Company redeemed the remaining 2,449 shares of preferred stock for cash totaling $31.3 million. Additionally, direct transaction-related costs of $1.1 million were incurred as part of the redemption. The excess of the cash settlement and direct transaction-related costs over the carrying value of the redeemed shares of preferred stock, totaling approximately $29.9 million, was treated as a deemed dividend and recorded as a reduction to retained earnings. The cash outflows related to the preferred stock redemption and associated fees are presented within financing activities on the consolidated statement of cash flows. The deemed dividend reduced net income available to common shareholders and impacted the calculation of earnings per share for the year ended December 31, 2025.

Dividends and Conversions

During the years ended December 31, 2025, 2024 and 2023 the Company paid $1.7 million, $4.2 million and $4.8 million, respectively, of cash dividends to holders of our preferred stock. No cash dividends were paid after the Redemption Date.

The following table summarizes activity of the Company's preferred stock for the years ended December 31, 2025 and 2024:

	2025	2024
Preferred stock as of January 1	37,348	44,214
Conversion of preferred stock	(4,461)	(11)
Preferred stock as of March 31	32,887	44,203
Conversion of preferred stock	(1,531)	(415)
Preferred stock as of June 30	31,356	43,788
Conversion of preferred stock	(28,907)	(43)
Redemption of preferred stock	(2,449)	—
Preferred stock as of September 30	—	43,745
Conversion of preferred stock	—	(6,397)
Preferred stock as of December 31	—	37,348

6. EQUITY

In May 2021, the Company filed an amended and restated certificate of incorporation with the Delaware Secretary of State to provide for, among other things, (i) the authority to issue 42 million shares of common stock with a par value of $0.0001 per share and (ii) the designation of 110,000 shares of preferred stock, with a par value of $0.0001 per share and a Liquidation Preference of $1,000 per share.

Common Stock

In May 2021, Gulfport issued approximately 19.8 million shares of common stock and 1.7 million shares of common stock were issued to the Disputed Claims Reserve.

In January 2024, the remaining 62,000 shares in the Disputed Claims Reserve were issued to certain claimants. There are no remaining shares in the Disputed Claims Reserve subsequent to the January 2024 issuance.

Stock Repurchase Program

In November 2021 the Company's Board of Directors approved the Repurchase Program to acquire up to $100 million of common stock, which has subsequently been increased up to $1.5 billion, including the cash redemption of preferred stock noted previously, and extended through December 31, 2026. Purchases under the Repurchase Program may be made from time to time in open market or privately negotiated transactions, and will be subject to available liquidity, market conditions, credit agreement restrictions, applicable legal requirements, contractual obligations and other factors. The Repurchase Program does not require the Company to acquire any specific number of shares of common stock. The Company intends to purchase shares under the Repurchase Program with available funds while maintaining sufficient liquidity to fund its capital development program. The Repurchase Program may be suspended from time to time, modified, extended or discontinued by the Board of Directors at any time.

The following table summarizes activity under the Repurchase Program for the year ended December 31, 2025 (number of shares and dollar value of shares purchased shown in thousands):

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid Per Share
First quarter 2025	341	$ 60,000	$ 176.13
Second quarter 2025	339	65,000	191.80
Third quarter 2025[1]	438	76,263	174.01
Fourth quarter 2025	665	134,999	203.11
Total	1,783	$ 336,262	$ 188.65

(1) Amounts include cash redemption of 2,449 shares of preferred stock (equivalent to 179,666 shares of common stock on an as-converted basis), totaling $31.3 million at $174.22 price per share. See Note 5 for further discussion of the Company's redemption of its preferred stock.

As of December 31, 2025, the Company has repurchased 7.4 million shares for $920.4 million at a weighted average price of $125.19 per share since the inception of the Repurchase Program.

7. STOCK-BASED COMPENSATION

In May 2021, the Board of Directors adopted the Incentive Plan with a share reserve of 2.8 million shares of common stock. The Incentive Plan provides for the grant of incentive stock options, nonstatutory stock options, restricted stock, restricted stock units, stock appreciation rights, dividend equivalents and performance awards or any combination of the foregoing.

The Company has granted both restricted stock units and performance vesting restricted stock units to employees and directors pursuant to the Incentive Plan, as discussed below. During the years ended December 31, 2025 and 2024, the Company's stock-based compensation expense was $18.1 million and $16.4 million of which the Company capitalized $6.0 million and $5.4 million, respectively, relating to its exploration and development efforts. Stock compensation expense, net of the amounts capitalized, is included in general and administrative expenses in the accompanying consolidated statements of operations. As of December 31, 2025, the Company has awarded an aggregate of approximately 516,677 restricted stock units and approximately 539,972 performance vesting restricted stock units under the Incentive Plan.

The vesting for certain share-based awards was accelerated in the first three months of 2023 in conjunction with the restructuring activities described in Note 13 and is included in restructuring costs in the accompanying consolidated statement of operations.

The following table summarizes activity for the years ended December 31, 2023, 2024 and 2025:

	Number of Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value	Number of Unvested Performance Vesting Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2022	197,772	$ 77.49	190,804	$ 52.15
Granted	104,901	88.59	83,820	58.39
Vested	(101,804)	75.75	—	—
Forfeited/canceled	(7,267)	91.61	(19,046)	49.37
Unvested shares as of December 31, 2023	193,602	$ 83.89	255,578	$ 54.40
Granted[(1)]	75,476	143.09	188,358	81.90
Vested	(96,942)	81.14	(265,797)	48.65
Forfeited/canceled	(5,122)	114.91	—	—
Unvested shares as of December 31, 2024	167,014	$ 111.29	178,139	$ 92.06
Granted	72,184	173.62	76,990	119.33
Vested	(90,720)	105.59	(71,948)	66.82
Forfeited/canceled	(4,812)	140.83	—	—
Unvested shares as of December 31, 2025	143,666	$ 145.22	183,181	$ 113.44

(1) The table includes the impacts of performance share units granted in a prior year that vested higher than 100% of target due to the Company's TSR performance compared to peers.

The aggregate fair value of share-based awards that vested during the years ended December 31, 2025, 2024 and 2023, was approximately $28.9 million, $56.8 million and $9.9 million, respectively, based on the stock price at the time of vesting.

In the second quarter of 2025, upon vesting, the Company settled in cash performance vesting restricted stock units awards that were granted in 2022. These awards vested at 200% of target due to the Company's performance during the performance period. The awards were classified as equity awards from the grant date as they were intended to be settled in shares. The Company has no history or stated policy of settling such awards in cash, and there is no implied obligation to do so in the future. The total cash outflow related to this settlement was $12.3 million.

Restricted Stock Units

Restricted stock units awarded under the Incentive Plan generally vest over a period of 3 years in the case of employees and 1 or 4 years in the case of directors upon the recipient meeting applicable service requirements. Stock-based compensation expense is recorded ratably over the service period. The grant date fair value of restricted stock units represents the closing market price of the Company's common stock on the date of the grant. Unrecognized compensation expense as of December 31, 2025, was $12.7 million. The expense is expected to be recognized over a weighted average period of 1.73 years.

Performance Vesting Restricted Stock Units

The Company has awarded performance vesting restricted stock units to certain of its executive officers under the Incentive Plan. The number of shares of common stock issued pursuant to the award will be based on a combination of (i) the Company's TSR and (ii) the Company's RTSR for the performance period. Participants will earn from 0% to 200% of the target award based on the Company's TSR and RTSR ranking compared to the TSR of the companies in the Company's designated peer group at the end of the performance period. Awards will be earned and vested at the end of a three-year performance period, subject to earlier termination of the performance period in the event of a change in control. The grant date fair values were determined using the Monte Carlo simulation method and are being recorded ratably over the performance period.

The table below summarizes the assumptions used in the Monte Carlo simulation to determine the grant date fair value of awards granted during the years ended December 31, 2023, 2024 and 2025:

Grant date	January 24, 2023	March 3, 2023	April 3, 2023	March 1, 2024	March 1, 2025
Forecast period (years)	3	3	3	3	3
Risk-free interest rates	3.88%	4.64%	3.79%	4.36%	3.99%
Implied equity volatility	87.2%	86.4%	70.8%	46.7%	44.6%
Stock price on the date of grant	$72.99	$82.20	$79.50	$142.00	$169.80

Unrecognized compensation expense as of December 31, 2025, related to performance vesting restricted shares was $7.6 million. The expense is expected to be recognized over a weighted average period of 1.60 years.

8. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue Recognition

The Company's revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. These sales are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at the time control of the product is transferred to the customer. Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

Gathering, processing and compression fees attributable to gas processing, as well as any transportation fees, including firm transportation fees, incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing and compression expense in the accompanying consolidated statements of operations.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature generally through evergreen contracts with contract terms of one year or less. These contracts typically automatically renew under the same provisions. For those contracts, the Company has utilized the practical expedient allowed in the revenue accounting standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, the Company's product sales that have a contractual term greater than one year have no long-term fixed consideration.

Contract Balances

Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $184.6 million, $155.9 million and $122.5 million as of December 31, 2025, 2024 and 2023, respectively, and are reported in accounts receivable - oil, natural gas, and natural gas liquids sales in the accompanying consolidated balance sheets. The Company has no assets or liabilities related to its revenue contracts, including no upfront or rights to deficiency payments as of December 31, 2025, 2024 and 2023.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain sales may be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The differences between the estimates and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. For each of the periods presented, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

9. LEASES

Nature of Leases

The Company has operating leases on certain equipment with remaining lease durations in excess of one year. The Company recognizes a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

The Company has historically entered into contracts for drilling rigs with varying terms with third parties to ensure operational continuity, cost control and rig availability in its operations. The Company has concluded its drilling rig contracts are operating leases as the assets are identifiable and the Company has the right to control the identified assets. The Company's drilling rig commitments are typically structured with an initial term of less than one year. At December 31, 2025, the Company did not have any active long-term drilling rig contracts. These agreements typically include renewal options at the end of the initial term. Due to the nature of the Company's drilling schedules and potential volatility in commodity prices, the Company is unable to determine at contract commencement with reasonable certainty if the renewal options will be exercised; therefore, renewal options are not considered in the lease term for drilling contracts. The operating lease liabilities associated with these rig commitments, when applicable, are based on the minimum contractual obligations, primarily standby rates, and do not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of drilling costs are borne by other interest owners in our wells.

The Company rents office space for its corporate headquarters, field locations and certain other equipment from third parties, which expire at various dates through 2027. These agreements are typically structured with non-cancelable terms of one year to five years. The Company has determined these agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. The Company has included any renewal options that it has determined are reasonably certain of exercise in the determination of the lease terms.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The Company's incremental borrowing rate reflects the estimated rate of interest that it would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment.

Future amounts due under operating lease liabilities as of December 31, 2025, were as follows (in thousands):

2026	561
2027	10
2028	—
2029	—
2030	—
Total lease payments	571
Less: imputed interest	(10)
Total	561

Lease costs incurred for the years ended December 31, 2025 and 2024 consisted of the following (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024
Operating lease cost	$ 2,053	$ 12,828
Variable lease cost	—	—
Short-term lease cost	31,547	26,817
Total lease cost[1]	$ 33,600	$ 39,645

(1) The majority of the Company's total lease cost was capitalized to the full cost pool, and the remainder was included in either lease operating expenses or general and administrative expenses in the accompanying consolidated statements of operations.

The weighted-average remaining lease term as of December 31, 2025, was 0.71 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2025, was 6.10%.

10. INCOME TAXES

Details of income tax provisions and deferred income taxes from continuing operations are provided in the following tables.

The components of income tax expense and benefits were as follows (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Current:			
State	$ —	$ —	$ —
Federal	—	—	—
Deferred:			
State	71	11,747	(26,704)
Federal	115,424	(67,824)	(498,452)
Total income tax expense (benefit) provision	$ 115,495	$ (56,077)	$ (525,156)

A reconciliation of the statutory federal income tax amount to the recorded expense (benefit) follows (in thousands):

	Year Ended December 31, 2025		Year Ended December 31, 2024		Year Ended December 31, 2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Income (loss) before federal income taxes	$ 543,305		$ (317,463)		$ 945,760	
U.S. federal statutory tax rate	114,094	21.00 %	(66,668)	21.00 %	198,610	21.00 %
State and local income taxes, net of federal income tax effect[1]	(479)	(0.09)%	8,939	(2.82)%	(26,018)	(2.75)%
Valuation allowances	(56)	(0.01)%	(259)	0.08 %	(699,730)	(73.99)%
Nontaxable or nondeductible items	1,745	0.32 %	1,857	(0.58)%	1,982	0.21 %
Tax credits	191	0.04 %	—	— %	—	— %
Other adjustments	—	— %	54	(0.02)%	—	— %
Income tax expense (benefit) recorded	$ 115,495	21.26 %	$ (56,077)	17.66 %	$ (525,156)	(55.53)%

(1) For 2025, 2024 and 2023, state taxes in Oklahoma contributed to the majority (greater than 50 percent) of the tax effect in this category.

For the year ended December 31, 2025, the Company's effective tax rate was 21.26% and an income tax expense of $115.5 million. For the year ended December 31, 2024, the Company's effective tax rate was 17.66% and an income tax benefit of $56.1 million. The higher effective income tax rate for the year ended December 31, 2025, is primarily related to the impact of state and local taxes during the year ended December 31, 2024.

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2025 and 2024 are estimated as follows (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024
Deferred tax assets:		
Net operating loss carryforward and tax credits	$ 330,805	$ 345,770
Oil and gas property basis difference	123,496	194,412
Investment in pass through entities	65,385	65,210
Stock-based compensation expense	2,223	1,821
Change in fair value of derivative instruments	—	6,106
Other assets	33,491	56,849
Total deferred tax assets	555,400	670,168
Valuation allowance for deferred tax assets	(82,637)	(83,695)
Deferred tax assets, net of valuation allowance	472,763	586,473
Deferred tax liabilities:		
Change in fair value of derivative instruments	6,232	3,401
Right of use asset	118	1,281
Other	675	558
Total deferred tax liabilities	7,025	5,240
Net deferred tax asset	$ 465,738	$ 581,233

At each reporting period, the Company weighs all available positive and negative evidence to determine whether its deferred tax assets are more likely than not to be realized. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. To assess the likelihood, the Company uses estimates and judgment regarding future taxable income and considers the tax laws in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, results of operations, both actual and forecasted, the reversal of deferred tax liabilities and tax planning strategies as well as the current and forecasted business economics of the oil and gas industry. Based upon the Company's analysis, the Company currently believes it is more-likely-than-not that a portion of the Company's federal and state deferred tax assets will be utilized. The Company has maintained a $82.6 million valuation allowance associated with its federal and state deferred tax assets. The Company does not currently have forecasted revenues in the jurisdictions that relate to these deferred tax assets.

The Company will continue to evaluate both the positive and negative evidence on a quarterly basis in determining the need for a valuation allowance with respect to the deferred tax assets. Changes in positive and negative evidence, including differences between estimated and actual results, could result in changes in the valuation of the deferred tax assets that could have a material impact on the consolidated financial statements. Changes in existing tax laws could also affect actual tax results and the realization of deferred tax assets over time.

The Company has an available federal tax net operating loss carryforward estimated at approximately $1.5 billion as of December 31, 2025. The federal net operating loss carryforwards of approximately $186.0 million generated in tax years prior to 2018 will begin to expire in 2036. As a result of the Tax Cuts and Jobs Act, the 2018 through 2025 federal NOL carryforwards of $1.3 billion have no expiration. The Company also has state net operating loss carryovers of approximately $473.8 million that will begin to expire in 2026.

As of December 31, 2025, we had no liability for uncertain tax positions.

11. EARNINGS (LOSS) PER SHARE

Basic income or loss per share attributable to common stockholders is computed as (i) net income or loss less (ii) dividends paid to holders of preferred stock less (iii) net income or loss attributable to participating securities divided by (iv) weighted average basic shares outstanding. Diluted net income or loss per share attributable to common stockholders is computed as (i) basic net income or loss attributable to common stockholders plus (ii) diluted adjustments to income allocable to participating securities divided by (iii) weighted average diluted shares outstanding. The "if-converted" method is used to determine the dilutive impact for the Company's convertible preferred stock and the treasury stock method is used to determine the dilutive impact of unvested restricted stock.

During the year ended December 31, 2025, the Company redeemed 2,449 shares of preferred stock for cash totaling $31.3 million. Additionally, direct transaction-related costs of $1.1 million were incurred as part of the redemption. The excess of the cash settlement and direct transaction-related costs over the carrying value of the redeemed shares of preferred stock, totaling approximately $29.9 million, was treated as a deemed dividend and recorded as a reduction to retained earnings. The deemed dividend reduced net income available to common shareholders and impacted both basic and diluted earnings per share.

Restricted stock awards resulted in 0.2 million dilutive shares for the year ended December 31, 2025, 0.3 million anti-dilutive shares for the year ended December 31, 2024, and 0.3 million dilutive shares year ended December 31, 2023. There were 2.7 million and 3.2 million potential shares of common stock issuable due to the Company's convertible preferred stock for the years ended December 31, 2024 and 2023, respectively. The Company redeemed all outstanding preferred stock during the year ended December 31, 2025.

Reconciliations of the components of basic and diluted net income (loss) per common share are presented in the table below (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Net income (loss)	$ 427,810	$ (261,386)	$ 1,470,916
Dividends on preferred stock	(1,666)	(4,230)	(4,840)
Deemed dividend on preferred stock[1]	(29,986)	—	—
Participating securities - preferred stock[2]	—	—	(212,360)
Net income (loss) attributable to common stockholders	$ 396,158	$ (265,616)	$ 1,253,716
Re-allocation of participating securities	—	—	2,475
Diluted net income (loss) attributable to common stockholders	$ 396,158	$ (265,616)	$ 1,256,191
Basic Shares	18,223	18,050	18,645
Dilutive Shares	18,440	18,050	18,902
Basic EPS	$ 21.74	$ (14.72)	$ 67.24
Dilutive EPS	$ 21.48	$ (14.72)	$ 66.46

(1) Reflects the difference between the carrying value of the preferred stock and the cash settlement upon redemption, including $1.1 million in direct transaction-related costs.
(2) Preferred stock represents participating securities because it participates in any dividends on shares of common stock on a *pari passu*, pro rata basis. However, preferred stock does not participate in undistributed net losses.

12. DERIVATIVE INSTRUMENTS

Natural Gas, Oil and NGL Derivative Instruments

The Company seeks to mitigate risks related to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, costless collars and various types of option contracts. These contracts allow the Company to mitigate the impact of declines in future natural gas, oil and NGL prices by effectively locking in a floor price for a certain level of the Company's production. However, these hedge contracts also limit the benefit to the Company in periods of favorable price movements.

The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. Gulfport may enter into commodity derivative contracts up to limitations set forth in its Credit Facility. The Company generally enters into commodity derivative contracts for approximately 30% to 70% of its forecasted current year annual production by the end of the first quarter of each fiscal year. The Company typically enters into commodity derivative contracts for the next 12 to 36 months. Gulfport does not enter into commodity derivative contracts for speculative purposes.

The Company does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. The Company's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings. Gulfport routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings and avoiding the concentration of credit exposure by transacting with multiple counterparties. The Company has master netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation. As of December 31, 2025, our commodity derivative contracts were spread among 13 counterparties.

Fixed price swaps require that the Company receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. They are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume.

The Company has entered into natural gas, crude oil and NGL fixed price swap contracts based off the NYMEX Henry Hub, NYMEX WTI and Mont Belvieu C3 indices. Below is a summary of the Company's open fixed price swap positions as of December 31, 2025:

	Index	Daily Volume	Weighted Average Price
Natural Gas		**(MMBtu/d)**	**($/MMBtu)**
2026	NYMEX Henry Hub	310,000	$ 3.80
2027	NYMEX Henry Hub	170,000	$ 3.95
NGL		**(Bbl/d)**	**($/Bbl)**
2026	Mont Belvieu C3	2,496	$ 30.91

Each two-way costless collar has a set floor and ceiling price for the hedged production. They are settled monthly based on differences between the floor and ceiling prices specified in the contract and the referenced settlement price. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the collar contracts, the Company will cash-settle the difference with the hedge counterparty. When the referenced settlement price is less than the floor price in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the hedged contract volume. Similarly, when the referenced settlement price exceeds the ceiling price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the hedged contract volume. No payment is due from either party if the referenced settlement price is within the range set by the floor and ceiling prices.

The Company has entered into natural gas costless collars based off the NYMEX Henry Hub index. Below is a summary of the Company's costless collar positions as of December 31, 2025:

	Index	Daily Volume	Weighted Average Floor Price	Weighted Average Ceiling Price
Natural Gas		**(MMBtu/d)**	**($/MMBtu)**	**($/MMBtu)**
2026	NYMEX Henry Hub	154,932	$ 3.63	$ 4.37
2027	NYMEX Henry Hub	110,000	$ 3.75	$ 4.27

In addition, the Company has entered into natural gas basis swap positions. These instruments are arrangements that guarantee a fixed price differential to NYMEX Henry Hub from a specified delivery point. The Company receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity. As of December 31, 2025, the Company had the following natural gas basis swap positions open:

	Gulfport Pays	Gulfport Receives	Daily Volume	Weighted Average Fixed Spread
Natural Gas			(MMBtu/d)	($/MMBtu)
2026	Rex Zone 3	NYMEX Plus Fixed Spread	80,000	$ (0.18)
2026	NGPL TXOK	NYMEX Plus Fixed Spread	30,000	$ (0.30)
2026	TETCO M2	NYMEX Plus Fixed Spread	170,000	$ (0.95)
2026	Transco Station 85	NYMEX Plus Fixed Spread	10,000	$ 0.56
2026	TGP 500	NYMEX Plus Fixed Spread	20,000	$ 0.56
2027	Rex Zone 3	NYMEX Plus Fixed Spread	20,000	$ (0.16)
2027	NGPL TXOK	NYMEX Plus Fixed Spread	10,000	$ (0.29)
2027	TETCO M2	NYMEX Plus Fixed Spread	50,000	$ (0.91)

Balance Sheet Presentation

The Company reports the fair value of derivative instruments on the consolidated balance sheets as derivative instruments under current assets, noncurrent assets, current liabilities, and noncurrent liabilities on a gross basis. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The following table presents the fair value of the Company's derivative instruments on a gross basis at December 31, 2025 and December 31, 2024 (in thousands):

	December 31, 2025	December 31, 2024
Short-term derivative asset	$ 45,155	$ 58,085
Long-term derivative asset	15,303	6,003
Short-term derivative liability	(21,865)	(41,889)
Long-term derivative liability	(8,916)	(35,081)
Total commodity derivative position	$ 29,677	$ (12,882)

Gains and Losses

The following table presents the gain and loss recognized in net gain (loss) on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the years ended December 31, 2025, 2024 and 2023 (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Natural gas derivatives - fair value gains (losses)	$ 39,010	$ (251,019)	$ 584,563
Natural gas derivatives - settlement gains	47,705	284,626	146,381
Total gains on natural gas derivatives	86,715	33,607	730,944
Oil and condensate derivatives - fair value (losses) gains	(3,468)	2,351	5,971
Oil and condensate derivatives - settlement gains (losses)	9,124	166	(3,272)
Total gains on oil and condensate derivatives	5,656	2,517	2,699
NGL derivatives - fair value gains (losses)	7,017	(4,442)	(2,414)
NGL derivatives - settlement (losses) gains	(332)	(2,155)	9,090
Total gains (losses) on NGL derivatives	6,685	(6,597)	6,676
Total gains on natural gas, oil and NGL derivatives	$ 99,056	$ 29,527	$ 740,319

Offsetting of Derivative Assets and Liabilities

As noted above, the Company records the fair value of derivative instruments on a gross basis. The following table presents the gross amounts of recognized derivative assets and liabilities in the consolidated balance sheets and the amounts that are subject to offsetting under master netting arrangements with counterparties, all at fair value (in thousands):

	As of December 31, 2025		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
Derivative assets	$ 60,458	$ (30,671)	$ 29,787
Derivative liabilities	$ (30,781)	$ 30,671	$ (110)

	As of December 31, 2024		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
Derivative assets	$ 64,088	$ (49,343)	$ 14,745
Derivative liabilities	$ (76,970)	$ 49,343	$ (27,627)

Concentration of Credit Risk

By using derivative instruments that are not traded on an exchange, the Company is exposed to the credit risk of its counterparties. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. When the fair value of a derivative instrument is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company's derivative contracts are spread between multiple counterparties to lessen its exposure to any individual counterparty. Additionally, the Company uses master netting agreements to minimize credit risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. None of the Company's derivative instrument contracts contain credit-risk related contingent features. Other than as provided by the Company's revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under its derivative instruments, nor are the counterparties required to provide credit support to the Company.

13. RESTRUCTURING COSTS

During the year ended December 31, 2023, Gulfport recognized $4.8 million in personnel-related restructuring expenses associated with changes in the organizational structure and leadership team resulting from the appointment of Gulfport's new CEO in January 2023. Of these expenses, $1.3 million resulted from accelerated vesting of certain share-based grants, which are non-cash charges. The organizational changes were completed in the second quarter of 2023 and there are no remaining employee termination liabilities associated with these changes.

14. INVESTMENTS

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings, owns an approximate 24.5% interest in Grizzly, a Canadian unlimited liability company. As of December 31, 2025, Grizzly had approximately 639,000 net acres under lease in the Athabasca, Peace River, and Cold Lake regions of Alberta, Canada. The Company has not paid any cash calls since its decision to cease funding further capital calls in 2019. Grizzly's functional currency is the Canadian dollar.

The Company reduced the carrying value of its investment in Grizzly to zero upon the Emergence Date. The reduction in valuation was based upon the Company's new management's assessment of the investment and its priority for future funding in its portfolio. In particular, Grizzly's operations remained suspended, even with improvements in the pricing environment since its initial suspension in 2015. Additionally, the Company does not anticipate funding future capital calls, which will lead to further dilution of its equity ownership interest.

15. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. Fair value measurements are classified and disclosed in one of the following categories:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Financial assets and liabilities

The following tables summarize the Company's financial and non-financial assets and liabilities by valuation level as of December 31, 2025 and December 31, 2024 (in thousands):

	December 31, 2025		
	Level 1	Level 2	Level 3
Assets:			
Derivative instruments	$ —	$ 60,458	$ —
Contingent consideration arrangement	$ —	$ —	$ 1,290
Total assets	$ —	$ 60,458	$ 1,290
Liabilities:			
Derivative instruments	$ —	$ 30,781	$ —

	December 31, 2024		
	Level 1	Level 2	Level 3
Assets:			
Derivative instruments	$ —	$ 64,088	$ —
Contingent consideration arrangement	$ —	$ —	$ 2,700
Total assets	$ —	$ 64,088	$ 2,700
Liabilities:			
Derivative instruments	$ —	$ 76,970	$ —

The Company estimates the fair value of all derivative instruments using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.

In connection with the SCOOP water infrastructure sale completed in the first quarter of 2020, the Company retained a contingent consideration arrangement. As of December 31, 2025, the fair value of the arrangement was $1.3 million, with $0.1 million classified within prepaid expenses and other current assets and $1.2 million classified within other assets. Fair value is measured using an income approach applying a discounted cash flow model and Level 3 inputs. The Company has elected the fair value option, and changes in fair value are recognized in earnings within Other, net.

Non-financial assets and liabilities

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 3 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred were $0.6 million and $0.7 million for the years ended December 31, 2025 and 2024, respectively.

Fair value of other financial instruments

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the Company's Credit Facility is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

16. RELATED PARTY TRANSACTIONS

Share Repurchase Program

The following table summarizes the Company's purchases of its common stock from Silver Point Capital, L.P. for the years ended December 31, 2024 and 2025 (dollar value of shares purchased shown in thousands):

Date of Transaction	Shares Repurchased	Repurchase Amount	Closing Date
March 19, 2024	97,219	$ 15,002	March 19, 2024
September 19, 2024	170,000	$ 24,863	September 25, 2024
November 21, 2024	150,000	$ 26,340	December 03, 2024
December 19, 2024	79,410	$ 12,929	December 26, 2024
May 14, 2025	76,986	$ 15,000	May 20, 2025
December 02, 2025	45,546	$ 10,000	December 08, 2025

The repurchases are part of the Company's existing Repurchase Program. Upon closing of the transactions, the repurchased common stock was canceled.

17. COMMITMENTS

Firm Transportation and Gathering Agreements

The Company has contractual commitments with midstream and pipeline companies for future gathering and transportation of natural gas from the Company's producing wells to downstream markets. Under certain of these agreements, the Company has minimum daily volume commitments. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it often can release it to other counterparties, thus reducing the cost of these commitments. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to future firm transportation and gathering agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, costs associated with utilized future firm transportation and gathering agreements are reflected in the Company's estimates of proved reserves.

A summary of these commitments at December 31, 2025, are set forth in the table below (in thousands):

2026	$	138,975
2027		133,932
2028		136,060
2029		137,282
2030		116,304
Thereafter		375,110
Total	$	1,037,663

Future Firm Sales Commitments

The Company has entered into various firm sales contracts to deliver and sell natural gas. The Company expects to fulfill its delivery commitments primarily with production from proved developed reserves. The Company's operated production has generally been sufficient to satisfy its delivery commitments during the periods presented, and it expects its operated production will continue to be the primary means of fulfilling its future commitments. However, where the Company's operated production is not sufficient to satisfy its delivery commitments, it can and may use spot market purchases to satisfy the commitments.

A summary of these volume commitments at December 31, 2025, are set forth in the table below (MMBtu per day):

2026	75,000
2027	24,000
2028	65,000
2029	65,000
Thereafter	520,000
Total	749,000

Other Operational Commitments

The Company entered into various contractual commitments to purchase inventory and other material to be used in future activities. The Company's commitment to purchase these materials exists through 2026, with approximately $16.4 million remaining.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) plan under which eligible employees may contribute a portion of their total compensation up to the maximum threshold through salary deferrals. The plan is considered a Safe Harbor 401(k) and provides a company match on 100% of salary deferrals that do not exceed 6% of compensation. The Company may also make discretionary elective contributions to the plan. The following table summarizes the contributions expenses related to this plan for the years ended December 31, 2025, 2024 and 2023 (in thousands):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Contributions expense	$ 2,043	$ 1,749	$ 1,549

18. CONTINGENCIES

The Company is involved in a number of litigation and regulatory proceedings including those described below. Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. The Company's total accrued liabilities 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, its 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 their final liabilities may ultimately be materially different. In accordance with ASC Topic 450, *Contingencies*, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Litigation and Regulatory Proceedings

The Company, along with other oil and gas companies, have been named as a defendant in a number of lawsuits where Plaintiffs assert their respective leases are limited to the Utica/Marcellus shale geological formations and allege that Defendants have willfully trespassed and illegally produced oil, natural gas, and other hydrocarbon products beyond these respective formations. They also allege that Defendants engaged in conversion and were unjustly enriched. Plaintiffs seek the full value of any production from below the Utica/Marcellus shale formations, unspecified damages from the diminution of value to their mineral estate, unspecified punitive damages, and the payment of reasonable attorney fees, legal expenses, and interest. On April 27, 2021, the Bankruptcy Court for the Southern District of Texas approved a settlement agreement in which the plaintiffs fully released the Company from all claims that accrued and any damages related to the period before the effective date of the Company’s Chapter 11 plan, which occurred on May 17, 2021. The plaintiffs are continuing to pursue alleged damages after May 17, 2021.

The Company received Notice and Finding of Violations (“NOV/FOVs”) from the USEPA alleging violations of the Clean Air Act at 17 locations in Ohio between 2013 and 2019. On January 22, 2020, the Company entered a Consent Decree with the Department of Justice and USEPA addressing Gulfport's failure to capture and control air emissions from storage vessels and to comply with associated inspection, recordkeeping, and reporting requirements. During the process of terminating the Consent Decree, the Company was informed that there were untimely repairs on a number of locations subject to the Company's Consent Decree that failed to comply with Subpart OOOO or Permit to Install and Operate Applications. On July 31, 2024, the Company received a NOV/FOV from USEPA related to the alleged untimely repairs. On September 30, 2025, the Company entered into a Consent Agreement and Final Order with USEPA fully resolving the NOV/FOVs for $454,403.

In November 2020, Robert T. Stephenson and Sandra J. Bass, as the Successor Co-Trustees of the Robert L. Stephenson Living Trust, dated January 28, 2004, and express trust; and Norma E. Stephenson, Trustee of the Norma E. Stephenson Living Trust, dated July 29, 1991, and express trust filed an action against the Company in the District Court of Grady County in the State of Oklahoma. In June 2021 the case was removed to the United States District Court for the Western District of Oklahoma. The complaint alleges that the Company has failed to comply with a Letter Agreement from April 1979 granting certain interests covering 16 sections (approximately 10,240 acres). The plaintiffs seek quiet title, declaratory judgment, breach of contract, specific performance, and damages under the Oklahoma Production Revenue Standards Act. Gulfport asserted a counterclaim. On February 2, 2026, the Company resolved all disputed claims and purchased all of the plaintiff's purported interests in the 16 sections related to the litigation.

In January 2025, Grace E. Moore Great Grandchildren Trust of 2006, Joseph Gorsha, Damon Faldowski, Damon Faldowski II, and Mark Faldowski, individually and on behalf of all others similarly situated, filed a class action against Gulfport and another natural gas producer in the United States District Court, Southern District of Ohio, Eastern Division. The lawsuit alleges, among other things, that defendants underpaid royalties to the plaintiffs in connection with the production and sale of natural gas and NGL involving a variety of lease forms. The lawsuit seeks compensatory damages, injunctive relief regarding royalty payment practices, restitution, disgorgement of profits, prejudgment interest, post-judgment interest, attorney’s fees, and costs. In April 2025, the United States Court of Appeals for the Sixth Circuit ruled that another operator in Ohio could not deduct certain processing and fractionation charges under one lease form that included a version of a market enhancement clause. Given the preliminary nature of this action, we are currently unable to estimate what liability may result from this matter.

Business Operations

The Company is involved in various lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for Gulfport and its subsidiaries. Gulfport and its subsidiaries have implemented various policies, programs, procedures, training and audits to reduce and mitigate environmental risks. The Company conducts periodic reviews, on a company-wide basis, to assess changes in its environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. The Company manages its 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, it may, among other things, exclude a property from the transaction, require the seller to remediate the property to its satisfaction in an acquisition or agree to assume liability for the remediation of the property.

Other Matters

Based on management's current assessment, they are of the opinion that no pending or threatened lawsuit or dispute relating to its business operations is likely to have a material adverse effect on their 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.

Concentration of Credit Risk

Gulfport operates in the oil and natural gas industry principally in the states of Ohio and Oklahoma with sales to refineries, re-sellers such as marketers, and other end users. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash in bank deposit accounts which, at times, may exceed the federally insured limits

During the years ended December 31, 2025, 2024 and 2023, one customer accounted for approximately 14%, 15% and 12%, respectively, of the Company's total sales. The Company does not believe that the loss of any of these customers would have a material adverse effect on its natural gas, oil and condensate and NGL sales as alternative customers are readily available.

19. SUBSEQUENT EVENTS

Natural gas, Oil and NGL Derivative Instruments

Subsequent to December 31, 2025 and as of February 19, 2026, the Company entered into the following derivative contracts:

Period	Type of Derivative Instrument	Index	Daily Volume	Weighted Average Price
Natural Gas			**(MMBtu/d)**	**($/MMBtu)**
2026	Swaps	NYMEX Henry Hub	36,603	$3.86
2027	Swaps	NYMEX Henry Hub	40,000	$3.80
2027	Basis Swaps	TETCO M2	50,000	$(0.80)
2027	Basis Swaps	Rex Zone 3	30,000	$(0.22)
2027	Basis Swaps	NGPL TXOK	30,000	$(0.34)
Oil			**(Bbl/d)**	**($/Bbl)**
2026	Costless Collars	NYMEX WTI	1,125	$55.00 / $71.18
2027	Costless Collars	NYMEX WTI	300	$55.00 / $68.00

20. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (UNAUDITED)

The Company is making the following supplemental disclosures of oil and gas activities, in accordance with the full cost method of accounting for its oil and gas exploration and development activities. The Company owns a 24.5% interest in Grizzly. However, Grizzly did not have any material activity or proved reserves in the years presented below. As such, amounts related to Grizzly have been omitted below.

The following table provides historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities (in thousands)

	Year Ended December 31, 2025	Year Ended December 31, 2024
Proved properties	$ 3,902,539	$ 3,349,805
Unproved properties	232,959	221,650
Total oil and natural gas properties	4,135,498	3,571,455
Accumulated depletion and amortization	(1,861,570)	(1,559,546)
Net capitalized costs	$ 2,273,928	$ 2,011,909

Costs Incurred in Oil and Gas Property Acquisition, Development and Exploratory Activities (in thousands)

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Acquisition	$ 83,601	$ 89,646	$ 93,905
Development	480,442	373,284	419,431
Exploratory	—	—	—
Total	$ 564,043	$ 462,930	$ 513,336

Capitalized interest is included as part of the cost of oil and natural gas properties. The Company capitalized $6.2 million, $4.8 million and $4.1 million for the years ended December 31, 2025, 2024 and 2023, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $25.2 million, $25.3 million and $22.8 million during the years ended December 31, 2025, 2024, and 2023, respectively, which were directly related to the acquisition, exploration and development of the Company's oil and natural gas properties.

Results of Operations for Producing Activities (in thousands)

The following table sets forth the revenues and expenses related to the production and sale of oil and natural gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Revenues	$ 1,323,527	$ 928,604	$ 1,051,383
Production costs	(473,088)	(451,086)	(450,996)
Depletion	(302,024)	(324,078)	(318,473)
Impairment	—	(373,214)	—
Income tax (expense) benefit	(115,495)	56,077	525,156
Results of operations from producing activities	$ 432,920	$ (163,697)	$ 807,070
Depletion per Mcf of gas equivalent (Mcfe)	$ 0.80	$ 0.84	$ 0.83

Oil and Natural Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2025, 2024 and 2023 and changes in proved reserves during the last three years. The reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2025, 2024 and 2023, in accordance with guidelines of the SEC applicable to reserves estimates. The prices used for the 2025 reserve report are $66.01 per barrel of oil, $3.39 per MMbtu for natural gas and $30.17 per barrel for NGL, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2024 and 2023 for reserve report purposes are $76.32 per barrel, $2.13 per MMbtu and $31.30 per barrel for NGL and $78.21 per barrel, $2.64 per MMbtu and $31.42 per barrel for NGL, respectively.

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	Oil (MMBbl)	Natural Gas (Bcf)	NGL (MMBbl)	Natural Gas Equivalent (Bcfe)
Proved Reserves				
December 31, 2022	18	3,612	54	4,048
Purchases of reserves	—	—	—	—
Extensions and discoveries	6	875	14	996
Sales of reserves	—	—	—	—
Revisions of prior reserve estimates	(4)	(411)	(1)	(445)
Current production	(1)	(350)	(4)	(385)
December 31, 2023	19	3,725	63	4,214
Purchases of reserves	—	—	—	—
Extensions and discoveries	5	398	20	547
Sales of reserves	—	—	—	—
Revisions of prior reserve estimates	—	(413)	1	(406)
Current production	(1)	(354)	(4)	(386)
December 31, 2024	22	3,356	80	3,969
Purchases of reserves	—	—	—	—
Extensions and discoveries	3	616	11	701
Sales of reserves	—	—	—	—
Revisions of prior reserve estimates	1	(22)	(4)	(38)
Current production	(2)	(338)	(5)	(379)
December 31, 2025	24	3,612	83	4,253
Proved developed reserves				
December 31, 2022	9	2,034	34	2,295
December 31, 2023	6	1,980	31	2,203
December 31, 2024	7	1,879	31	2,109
December 31, 2025	8	2,157	33	2,404
Proved undeveloped reserves				
December 31, 2022	9	1,578	20	1,752
December 31, 2023	12	1,746	32	2,011
December 31, 2024	15	1,478	49	1,861
December 31, 2025	16	1,455	50	1,848

Totals may not sum or recalculate due to rounding.

2025 Activity

In 2025, the Company experienced extensions of 701 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica/Marcellus and SCOOP acreages. Of the total extensions, 382 Bcfe was attributable to the addition of 28 Utica PUD locations, 62 Bcfe was attributable to the addition of 7 Marcellus PUD locations, and 138 Bcfe was attributable to the addition of 6 SCOOP PUD locations. The Company also added 11 operated locations in the Utica to PDP which were not previously booked for 119 Bcfe.The Company experienced total downward revisions of 38 Bcfe in estimated proved reserves. These consisted of upward revisions of 255 Bcfe which were associated with commodity price changes. Commodity prices experienced volatility throughout 2025 and the 12-month unweighted average first-day-of-the-month price for natural gas increased from $2.13 per MMBtu for 2024 to $3.39 per MMBtu for 2025, the 12-month average WTI spot price for crude oil decreased from $76.32 per barrel for 2024 to $66.01 per barrel for 2025, and the calculated average weighted price for NGL over the remaining lives of the properties decreased from $31.30 per barrel for 2024 to $30.17 per barrel for 2025. Additionally, there were upward revisions of 161 Bcfe due to an increase in working interest and net revenue interest as a result of our successful leasing efforts throughout 2025. These were offset by downward revisions of 185 Bcfe and 129 Bcfe as a result of development schedule changes and PUD well design changes, respectively. The schedule changes moved the development of 9 Utica PUD locations and 4 SCOOP PUD locations beyond the SEC requirement of development within five years from initial booking and while these locations are excluded from our SEC reserves report, they remain in our longer-term development plan. Design changes primarily include well spacing and lateral length updates with a portion of these volumes now to be developed with locations outside of the SEC designated five-year development time frame. These development schedule and design changes reflect our ongoing commitment to optimizing the long-term plan to best develop our assets and maximize cash flow and overall economic returns. Finally, downward revisions of 141 Bcfe were a result of a combination of various economic assumptions and well performance updates.

2024 Activity

In 2024, the Company experienced extensions of 547.5 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica/Marcellus and SCOOP acreages. Of the total extensions, 340.7 Bcfe was attributable to the addition of 33 Utica PUD locations, 92.4 Bcfe was attributable to the addition of 13 Marcellus PUD locations, and 114.4 Bcfe was attributable to the addition of 16 SCOOP PUD locations. The Company experienced total downward revisions of 406.0 Bcfe in estimated proved reserves. These consisted of upward revisions of 16.2 Bcfe as a result of positive well performance and 171.2 Bcfe due to an increase in working interest and net revenue interest as a result of our successful leasing efforts through 2024. These were offset by downward revisions of 487.9 Bcfe which were due to commodity price changes. Commodity prices experienced volatility throughout 2024 and the 12-month average price for natural gas decreased from $2.64 per MMBtu for 2023 to $2.13 per MMBtu for 2024, the 12-month average price for NGL decreased from $31.42 per barrel for 2023 to $31.30 per barrel for 2024, and the 12-month average price for crude oil decreased from $78.21 per barrel for 2023 to $76.32 per barrel for 2024. Additionally, downward revisions of 172.4 Bcfe were primarily a result of development schedule changes with some PUD well design changes. The schedule changes moved the development of 11 Utica/Marcellus PUD locations and 6 SCOOP PUD locations beyond the SEC requirement of developing these wells five years from initial booking. The development schedule changes reflect our ongoing commitment to optimizing the long-term plan to best develop our asset and maximize cash flow and overall economic returns. These locations excluded from our SEC reserves report remain in Gulfport's development plan. Finally, upward revisions of 66.9 Bcfe were a result of a combination of various economic assumption updates.

2023 Activity

In 2023, the Company experienced extensions of 995.7 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica/Marcellus and SCOOP acreages. Of the total extensions, 789.2 Bcfe was attributable to the addition of 67 Utica PUD locations, 88.6 Bcfe was attributable to the addition of 12 Marcellus PUD locations, and 110.4 Bcfe was attributable to the addition of 14 SCOOP PUD locations. The Company experienced total downward revisions of 444.9 Bcfe in estimated proved reserves. These consisted of upward revisions of 24.9 Bcfe as a result of positive well performance and 293.9 Bcfe due to an increase in working interest and net revenue interest as a result of our successful leasing efforts through 2023. These were offset by downward revisions of 554.9 Bcfe which were primarily a result of development schedule changes with some PUD well design changes. The schedule changes moved the development of 36 Utica/Marcellus PUD locations and 8 SCOOP PUD locations beyond the SEC requirement of developing these wells five years from initial booking. The development schedule changes reflect our ongoing commitment to optimizing the long-term plan to best develop our asset and maximize cash flow and overall economic returns. These locations excluded from our SEC reserves report remain in Gulfport's development plan. Additionally, downward revisions of 159.7 Bcfe due to commodity price changes. Commodity prices experienced volatility throughout 2023 and the 12-month average price for natural gas decreased from $6.36 per MMBtu for 2022 to $2.64 per MMBtu for 2023, the 12-month average price for NGL increased from $47.86 per barrel for 2022 to $31.42 per barrel for 2023, and the 12-month average price for crude oil decreased from $94.14 per barrel for 2022 to $78.21 per barrel for 2023. Finally, downward revisions of 49.1 Bcfe were a result of a combination of various economic assumption updates.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following tables present the estimated future cash flows, and changes therein, from Gulfport's proven oil and gas reserves as of December 31, 2025, 2024 and 2023 using an unweighted average first-of-the-month price for the year January through December 31, 2025, 2024 and 2023. The average gas prices used were $3.39, $2.13 and $2.64 per MMbtu, for the years ended December 31, 2025, 2024 and 2023, respectively. The average oil prices used were $66.01, $76.32 and $78.21 per Bbl, for the years ended December 31, 2025, 2024 and 2023, respectively. The average NGL prices used were $30.17, $31.30 and $31.42 per Bbl, for the years ended December 31, 2025, 2024 and 2023, respectively.

Year ended operating expenses, development costs and appropriate statutory income tax rates, with consideration of future tax rates, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop proved developed non-producing and proved undeveloped reserves are approximately $337.2 million in 2026, $328.4 million in 2027 and $311.2 million in 2028. Estimated future development costs include capital spending on major development projects. Gulfport believes cash flow from its operating activities, cash on hand and borrowings under its Credit Facility will be sufficient to cover these estimated future development costs.

The assumptions used to derive the standardized measure of discounted future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The information may be useful for certain comparative purposes but should not be solely relied upon in evaluating Gulfport or its performance. Furthermore, information contained in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves. Management believes that the following factors should be considered when reviewing the information below:

- Future commodity prices received for selling the Company's net production will likely differ from those required to be used in these calculations.
- Future operating and capital costs will likely differ from those required to be used in these calculations and do not reflect cost savings of Company owned midstream operations on future operating expenses.
- Future market conditions, government regulations, reservoir conditions and risks inherent in the production of oil and condensate and gas may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

The following table summarizes estimated future net cash flows from natural gas and crude oil reserves (in millions):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Future cash flows	$ 15,130	$ 10,474	$ 12,338
Future development and abandonment costs	(1,632)	(1,498)	(1,625)
Future production costs	(6,266)	(5,268)	(5,641)
Future production taxes	(270)	(212)	(303)
Future income taxes	(547)	(23)	(63)
Future net cash flows	6,414	3,473	4,706
10% discount to reflect timing of cash flows	(3,012)	(1,726)	(2,323)
Standardized measure of discounted future net cash flows	$ 3,403	$ 1,747	$ 2,383

Totals may not sum or recalculate due to rounding.

Future development and abandonment costs include not only development costs but also all future costs to settle asset retirement obligations. The following table summarizes the total of all future costs to settle asset retirement obligations that are included in future development and abandonment costs above (in millions):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Future asset retirement obligations	$ 255	$ 240	$ 229

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The principal source of change in the standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below (in millions):

	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2023
Sales and transfers of oil and gas produced, net of production costs	$ (850)	$ (478)	$ (600)
Net changes in prices, production costs, and development costs	1,532	(910)	(7,181)
Acquisition of oil and gas reserves in place	—	—	—
Extensions and discoveries	518	368	581
Previously estimated development costs incurred during the period	246	211	263
Revisions of previous quantity estimates, less related production costs	(21)	(21)	(278)
Sales of oil and gas reserves in place	—	—	—
Accretion of discount	175	238	828
Net changes in income taxes	(209)	16	1,219
Change in production rates and other	266	(60)	(728)
Total change in standardized measure of discounted future net cash flows	$ 1,656	$ (636)	$ (5,896)

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and our Chief Financial Officer, and with participation of management, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2025, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and our Chief Financial Officer have concluded that, as of December 31, 2025, our disclosure controls and procedures are effective.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2025, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act of 1934. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the *2013 Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the *2013 Internal Control-Integrated Framework,* management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2025.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2025 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2025, as stated in their accompanying report.

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2025, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2025 and our report dated February 25, 2026 expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 25, 2026

ITEM 9B. OTHER INFORMATION

The disclosures set forth below are provided in this Part II, Item 9B in lieu of separate disclosure under Items 5.02(b)-(c) and (e) of Form 8-K.

Trading Arrangements

During the year ended December 31, 2025, none of our officers (as defined in Rule 16a-1(f) of the Exchange Act) or directors adopted or terminated any contract, instruction or written plan for the purchase or sale of our securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement" (as 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 and certain other senior 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 Gulfport pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than 120 days after the close of our fiscal year ended December 31, 2025 (the 2026 Proxy Statement).

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the 2026 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 2026 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 2026 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information called for by this Item 14 is incorporated herein by reference to the 2026 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements.* Gulfport'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

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date	
2.1	Amended Joint Chapter 11 Plan of Reorganization of Gulfport Energy Corporation and its Debtor Subsidiaries.	8-K	001-19514	2.2	4/29/2021	
3.1	Amended and Restated Certificate of Incorporation of Gulfport Energy Corporation.	8-K	001-19514	3.1	5/17/2021	
3.2	Amendment to the Amended and Restated Certificate of Incorporation of Gulfport Energy Corporation.	8-K	001-19514	3.1	5/23/2025	
3.3	Amended and Restated Bylaws of Gulfport Energy Corporation.	8-K	001-19514	3.2	5/17/2021	
4.1	1145 Indenture, dated as of May 17, 2021, by and among Gulfport Energy Corporation, UMB Bank, National Association, as trustee, and the guarantors party thereto (including the form of note attached thereto).	8-K	001-19514	4.1	5/17/2021	
4.2	4(a)(2) Indenture, dated as of May 17, 2021, by and among Gulfport Energy Corporation, UMB Bank, National Association, as trustee, and the guarantors party thereto (including the form of note attached thereto).	8-K	001-19514	4.2	5/17/2021	
4.3	Indenture, dated September 13, 2024, among Gulfport Energy Operating Corporation, Gulfport Energy Corporation, the subsidiary guarantors party thereto and UMB Bank, National Association, as trustee.	8-K	001-19514	4.1	9/16/2024	
4.4	Description of Securities Registered Pursuant to Section 12 of the Exchange Act.	10-K	001-19514	4.3	3/1/2023	
10.1+	Gulfport Energy Corporation 2021 Stock Incentive Plan.	8-K	001-19514	10.6	5/17/2021	
10.3+	Form of Director Restricted Stock Unit Award Agreement, dated as of July 21, 2021.	10-Q	001-19514	10.8	8/9/2021	
10.5+	Form of Indemnification Agreement.	S-4	333-199905	10.1	11/6/2014	
10.6+	CEO Agreement Amendment by and among Timothy Cutt and Gulfport, effective as of September 2, 2021.	8-K	001-19514	10.1	9/7/2021	

10.7+	Employment Agreement by and among William Buese and Gulfport, effective as of May 17, 2021.	8-K	001-19514	10.5	5/17/2021
10.8+	Employment Agreement between Gulfport Energy Corporation and Timothy Cutt, effective April 29, 2022.	10-Q	001-19514	10.2	5/4/2022
10.9+	Employment Agreement, by and between Gulfport Energy Corporation and John Reinhart, effective January 24, 2023.	8-K	001-19514	10.1	1/24/2023
10.10+	Indemnification Agreement, by and between Gulfport Energy Corporation and John Reinhart, effective January 24, 2023.	8-K	001-19514	10.2	1/24/2023
10.11+	Transition and Services Agreement, by and between Gulfport Energy Corporation and Timothy Cutt, effective February 1, 2023.	8-K	001-19514	10.3	1/24/2023
10.12	Cooperation Agreement, dated as of May 17, 2021, by and among Gulfport Energy Corporation and Silver Point Capital, L.P.	8-K	001-19514	10.3	5/17/2021
10.13	Registration Rights Agreement, dated as of May 17, 2021, by and among Gulfport Energy Corporation and the holders party thereto.	8-K	001-19514	10.2	5/17/2021
10.14*	Third Amended and Restated Credit Agreement, dated as of October 14, 2021, by and among Gulfport Energy Corporation, as holdings, Gulfport Energy Operating Corporation, as the borrower, JPMorgan Chase Bank, N.A., the lenders party thereto, and the guarantors party thereto.	8-K	001-19514	10.1	10/14/2021
10.15	Borrowing Base Redetermination Agreement and First Amendment to Credit Agreement, dated as of May 2, 2022.	10-Q	001-19514	10.1	5/4/2022
10.16	Borrowing Base Reaffirmation Agreement and Second Amendment to Credit Agreement, dated as of October 31, 2022.	10-Q	001-19514	10.1	11/2/2022
10.17+	Form of Employment Agreement.	10-K	001-19514	10.19	3/1/2023
10.18	Borrowing Base Reaffirmation Agreement and Third Amendment to Credit Agreement, dated as of May 1, 2023.	10-Q	001-19514	10.3	5/3/2023
10.19+	Change in Control Severance Agreement.	10-Q	001-19514	10.2	8/2/2023
10.20+	Employment Agreement between Gulfport Energy Corporation and Michael Hodges, effective April 3, 2023.	8-K	001-19514	10.1	4/3/2023
10.21+	Indemnification Agreement, by and between Gulfport Energy Corporation and Michael Hodges, effective April 3, 2023.	8-K	001-19514	10.2	4/3/2023
10.22	Commitment Increase, Borrowing Base Reaffirmation Agreement and Fourth Amendment to Credit Agreement dated September 12, 2024.	8-K	001-19514	10.1	9/16/2024
10.23+	Employment Agreement between Gulfport Energy Corporation and Patrick Craine, effective March 1, 2023.	10-K	001-19514	10.23	2/26/2025
10.24+	Employment Agreement between Gulfport Energy Corporation and Matthew Rucker, effective March 1, 2023.	10-K	001-19514	10.24	2/26/2025

10.25+	Employment Agreement between Gulfport Energy Corporation and Michael Sluiter, effective March 1, 2023.	10-K	001-19514	10.25	2/26/2025	
10.26+	Form of Performance-Based Restricted Stock Unit Award Agreement, dated as of April 29, 2022.	10-K	001-19514	10.26	2/26/2025	
10.27+	Form of Performance-Based Restricted Stock Unit Award Agreement, dated as of January 1, 2023.	10-K	001-19514	10.27	2/26/2025	
10.28+	Form of Non-Executive Restricted Stock Unit Award Agreement, dated as of May 24, 2023.	10-K	001-19514	10.28	2/26/2025	
10.29+	Form of Director Restricted Stock Unit Award Agreement, dated as of May 24, 2023.	10-K	001-19514	10.29	2/26/2025	
10.30+	Form of Performance-Based Restricted Stock Unit Award Agreement, dated as of January 1, 2024.	10-K	001-19514	10.3	2/26/2025	
10.31+	Form of Executive Restricted Stock Unit Award Agreement, dated as of February 29, 2024.	10-K	001-19514	10.31	2/26/2025	
10.32+	Form of Non-Executive Restricted Stock Unit Award Agreement, dated as of February 29, 2024.	10-K	001-19514	10.32	2/26/2025	
10.33+	Form of Director Restricted Stock Unit Award Agreement, dated as of May 23, 2024.	10-K	001-19514	10.33	2/26/2025	
10.34+	Form of Performance-Based Restricted Stock Unit Award Agreement, dated as of January 1, 2025.	10-K	001-19514	10.34	2/26/2025	
10.35+	Form of Executive Restricted Stock Unit Award Agreement, dated as of February 24, 2025.	10-K	001-19514	10.35	2/26/2025	
10.36+	Form of Non-Executive Restricted Stock Unit Award Agreement, dated as of February 24, 2025.	10-K	001-19514	10.36	2/26/2025	
10.37	Borrowing Base Reaffirmation Agreement and Fifth Amendment to Credit Agreement, dated as of October 30, 2025.					X
10.38+	Form of Director Restricted Stock Unit Award Agreement, dated as of May 19, 2025.					X
10.39+	Form of Performance-Based Restricted Stock Unit Award Agreement, dated as of February 23, 2026.					X
10.40+	Form of Executive Restricted Stock Unit Award Agreement, dated as of February 23, 2026.					X
10.41+	Form of Non-Executive Restricted Stock Unit Award Agreement dated as of February 23, 2026.					X
10.42+	Indemnification Agreement, by and between Gulfport Energy Corporation and Bradley Secrist, effective February 23, 2026.					X
10.43+	Indemnification Agreement, by and between Gulfport Energy Corporation and Matthew Willrath, effective February 23, 2026.					X
19	Insider Trading Policy.	10-K	001-19514	19	2/26/2025	

21	Subsidiaries of the Registrant.					X
23.1	Consent of Netherland, Sewell & Associates, Inc.					X
23.2	Consent of Grant Thornton LLP.					X
31.1	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.					X
31.2	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.					X
32.1	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.					X
32.2	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.					X
97.1	Clawback Policy.	10-K	001-19514	97.1	2/28/2024	
99.1	Report of Netherland, Sewell & Associates, Inc.					X
101.INS	Inline XBRL Instance 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

* Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

\+ Management contract, compensatory plan or arrangement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 25, 2026

GULFPORT ENERGY CORPORATION

By: /s/ MICHAEL HODGES

Michael Hodges
Chief Financial Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 25, 2026 By: /s/ JOHN REINHART

John Reinhart
President, Chief Executive Officer and Director
(Principal Executive Officer)

Date: February 25, 2026 By: /s/ MICHAEL HODGES

Michael Hodges
Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

Date: February 25, 2026 By: /s/ TIMOTHY J. CUTT

Timothy J. Cutt
Chairman of the Board

Date: February 25, 2026 By: /s/ DAVID WOLF

David Wolf
Lead Independent Director

Date: February 25, 2026 By: /s/ JASON MARTINEZ

Jason Martinez
Director

Date: February 25, 2026 By: /s/ JEANNIE POWERS

Jeannie Powers
Director

Date: February 25, 2026 By: /s/ DAVID REGANATO

David Reganato
Director

Date: February 25, 2026 By: /s/ MARY SHAFER-MALICKI

Mary Shafer-Malicki
Director