NOG

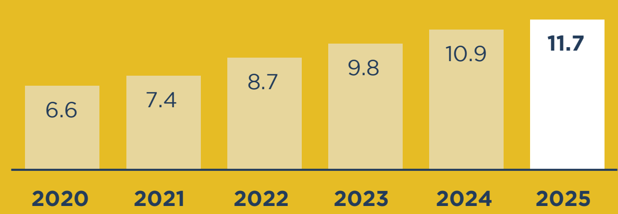
2025

Annual Report

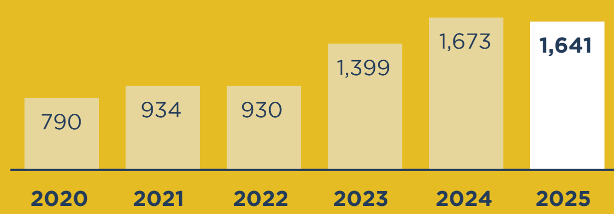
Northern Oil and Gas is distinguished by its:

SCALE

Gross Wells by Year (in thousands)

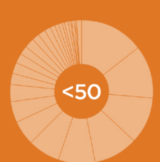


Gross Acreage by Year (in thousands)



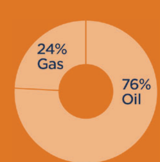
DIVERSIFICATION

2020 Operators

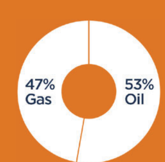


2025 Operators

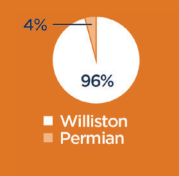
2020 Commodity Mix



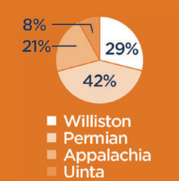
2025 Commodity Mix



2020 Production by Basin

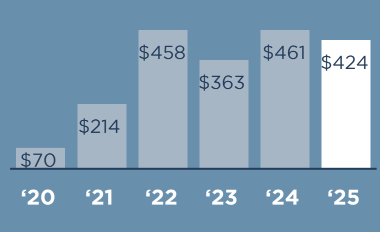


2025 Production by Basin

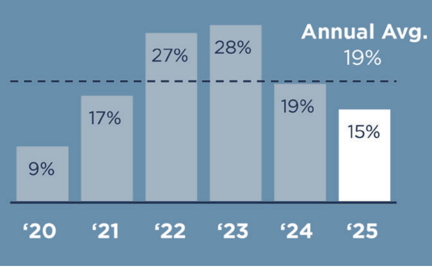


RESULTS

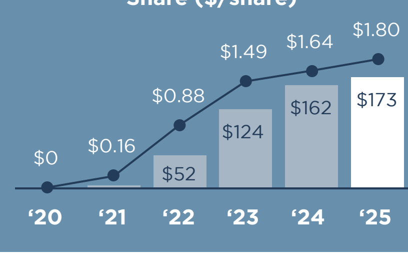
Free Cash Flow* ($millions)



Return on Capital Employed*



Total Dividends ($millions) and Dividends per Common Share ($/share)



* FCF and ROCE are non-GAAP financial measures. See Appendix A for reconciliations.

A Letter from the CEO

Dear Fellow Shareholders,

This year marks a meaningful milestone—five years since I assumed the role of Chief Executive Officer at Northern Oil and Gas, Inc. (NOG), and the occasion of our very first annual letter. It is an honor to reflect on the journey we've undertaken together, and I want to express my deepest gratitude to each of you for your trust and partnership. The past five years have been a period of remarkable transformation for NOG, defined by both significant challenges and extraordinary progress.

When I stepped into the CEO role in 2020, NOG stood at an inflection point. The oil and gas sector was entering a period of unprecedented volatility—marked by wild swings in commodity prices, rapid shifts in capital markets, and mounting uncertainty about the future of energy. These headwinds tested every aspect of our business and demanded swift, decisive action. Yet, they also illuminated opportunities for those willing to adapt with discipline and vision. Our response was not simply to weather the storm, but to seize the moment and fundamentally reimagine how a public non-operating exploration and production (E&P) company could operate with enduring success.

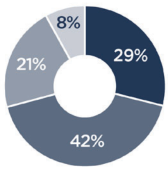
Back in 2020, NOG faced considerable hurdles: a leveraged balance sheet, concentrated exposure in a single basin, and limited financial resources with which to orchestrate a scaling of the business. I had joined NOG in 2018 from a career in oil and gas investment, convinced that the non-operated model—owning interests in wells without operating them—offered a superior way to generate value while managing risk. This conviction shaped our strategy as we pivoted to disciplined capital deployment, rigorous portfolio management, and a relentless focus on sustainable growth. Our goal was clear: build a resilient, investor-centric company capable of thriving through cycles, not just surviving them. We talked repeatedly of "a Company by Investors, for Investors." That wasn't just a tagline, it was and is fundamental to how we believe we can generate value.

Over the past five years, we have executed on this vision with determination. We diversified our asset base from a single-basin footprint into a national platform, acquiring high-quality interests in the Williston, Permian, Appalachian, and Uinta basins. Production and reserves increased substantially, and our free cash flow profile strengthened. We grew our team from 24 to 64 professionals, assembling a group of top-tier engineers, business strategists, and data experts—all united by a culture of accountability, innovation, and collaboration to support our rapidly

2025 was an atypical year for our industry featuring a multitude of macroeconomic and geopolitical headwinds.

Nonetheless, our business model and strategy delivered.

Diversification by Basin



~12,000/ 1,200

Gross/Net Wells

~300K

Net Acres

~100

Operators

* All data as of December 31, 2025

Northern Oil and Gas is the premier non-operated E&P with over **$6B of investments** in minority well interests since 2018. We have a **simple but powerful business model** built to deliver results through cycles.

scaling business. Each acquisition and portfolio decision was grounded in the principle of disciplined capital allocation—placing shareholder returns and risk management at the heart of every move. Notably, our disciplined approach delivered an average 19% return on capital employed from 2020 to 2025, underscoring our commitment to generating sustainable value for our investors.

Our non-operated model has been instrumental in achieving this transformation. By avoiding the operational burdens of running wells, we can allocate capital precisely where returns are most attractive, adapt to market conditions, and maintain an agile, low-overhead structure. This approach has allowed us to rebuild our balance sheet and restore investor confidence, and it has also positioned NOG as the partner of choice for co-investments and strategic ventures. Our ability to provide bridge capital while protecting our alignment with our operating partners reflects the value of our disciplined, investor-focused strategy.

Resilience has been our defining trait in a volatile market. Since 2018, NOG has executed more than $6 billion in opportunistic acquisitions, often moving decisively when others hesitated. We have maintained broad diversification, keeping our average well interest near 10%, and established robust controls over funding and governance in higher-ownership ventures. Our risk management practices, including diversification, hedging, and prudent leverage, have enabled us to deliver strong results while protecting against downside risks. Through these actions, we have returned more than $500 million in the form of dividends to shareholders since 2021, and have grown our enterprise value meaningfully—all while upholding our commitment to long-term value creation.

I cannot emphasize enough the evolution of the marketplace. In 2018, many others were focused on acquiring royalty and mineral interests, and viewed non-op working interest investments as an afterthought, even though we understood with a combination of technical underwriting abilities and risk management, non-op working interest investments generally delivered a vastly superior return. We found that the asset market disconnect created an enormous opportunity that had to be seized upon. Today, we are largely credited with establishing non-op assets as a true asset class within the energy domain. While this has changed the competitive landscape to some degree, we have continued to innovate in order to drive higher returns for our investors, finding new ways to acquire, structure and in some cases synthetically create non-op assets, often times creating vastly superior governance and informational rights along the way.

A key driver of our continued success is our commitment to technological innovation. In 2022, we launched Drakkar, NOG's proprietary data platform. Drakkar aggregates and analyzes data from our 12,000 wells, 100 operators, four basins, and two commodities, as well as historical deal data, type curves, and authorization for expenditure (AFE) data. This platform empowers our team with actionable intelligence, enhancing our decision-making and capital allocation capabilities. By harnessing the power of artificial intelligence (AI), Drakkar enables us to identify opportunities, optimize performance, and drive efficiency across our diversified portfolio, reinforcing NOG's position as an industry leader in data-driven energy investment.

At NOG, we are proud to operate with an investor's mindset—because that is where our roots lie. Every aspect of our business, from capital deployment to governance, is built to align with shareholder interests. Our board oversight is robust, and executive compensation is directly linked to long-term performance. Transparency, accountability, and a relentless focus on sustainable value are the cornerstones of our culture. We believe that by treating energy assets as a diversified portfolio, managed with rigor and foresight, we can deliver attractive returns while safeguarding against uncertainty.

Our purpose extends beyond financial results. We are committed to responsible energy investment and to making a positive difference for people, the planet, and our business. We have formalized our approach to environmental, social, and governance (ESG) responsibilities with clear policies, transparent reporting, and high standards for sustainability. Our partners are evaluated on both technical and ESG performance, reinforcing a culture of integrity and progress. As the only non-op member of the American Exploration & Production Council and a four-time recipient of Non-Op Company of the Year, NOG's reputation for responsible leadership stands as a testament to our values and vision.

Looking ahead, I am confident in NOG's ability to adapt and grow. We will continue to leverage our unique model, technical expertise, and disciplined approach to seize opportunities and drive innovation. Our vision remains centered on delivering sustainable value for our shareholders, supporting the energy transition with responsible practices, and building a resilient company prepared for whatever the future may hold.

As a result of our success, our reputation as a technically savvy capital provider with unmatched financial firepower has made us a partner of choice, which has provided us with one of the largest total addressable markets and opportunity sets in the entirety of the US energy industry. Our opportunity set to further grow and enhance returns for our investors remains unmatched, and our leading position only grows with each successive transaction we have executed.

Thank you for your continued support and partnership. I am inspired by what we have accomplished together, and excited for the next chapter as we pursue lasting success at NOG. We remain steadfast in our commitment to you, our shareholders, and look forward to building the future of energy—together.

Sincerely,

Nick O'Grady
Chief Executive Officer
Northern Oil and Gas, Inc.

~135.0

2025 Average Production MBOE/Day

~75.6

2025 Average Oil Production MBBL/Day

15.0%

2025 ROCE

1.4x

Net Debt: Adj. EBITDA*

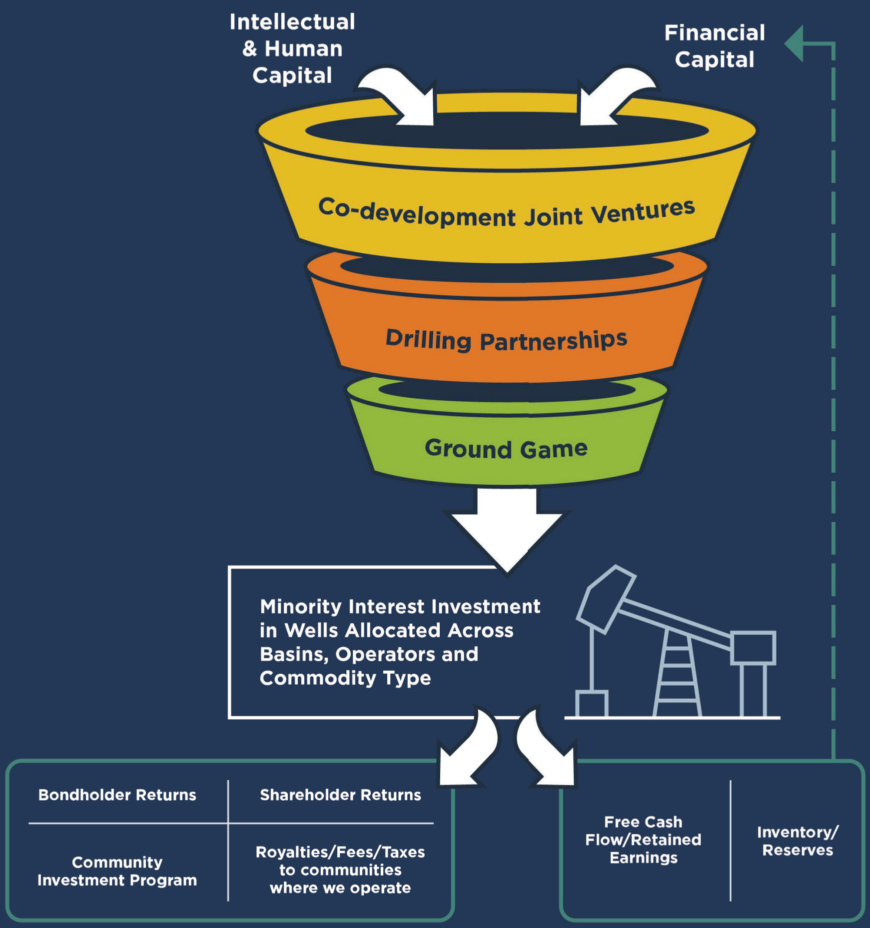
* As of December 31, 2025

Our Business

As a non-operating participant in the upstream oil and gas sector, NOG does not directly produce oil or natural gas nor develop or operate associated infrastructure.

With a limited physical footprint, no field-based staff, and minimal influence over exploration and production activities conducted on its acreage, NOG's role is primarily that of a financial stakeholder.

This is the primary difference between NOG, a non-operator, and conventional E&P companies.



UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

Or

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

For the transition period from ________ to ________

Commission File Number *001-33999*

NORTHERN OIL AND GAS, INC.

(*Exact Name of Registrant as Specified in Its Charter*)

Delaware	**95-3848122**
(*State or Other Jurisdiction of Incorporation or Organization*)	(*I.R.S. Employer Identification No.)*

4350 Baker Road – Suite 400, Minnetonka, Minnesota 55343
(*Address of Principal Executive Offices*) (*Zip Code*)

952-476-9800
(*Registrant's Telephone Number, Including Area Code*)

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	NOG	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

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

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

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

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter (based on the closing sale price on such date) was approximately $2.7 billion.

As of February 23, 2026, the registrant had 97,294,661 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the registrant's 2026 Annual Meeting of Stockholders (the "Proxy Statement") are incorporated by reference into Part III of this report for the year ended December 31, 2025.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect our company and to take advantage of the "safe harbor" protection for forward-looking statements that applicable federal securities law affords.

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, indebtedness covenant compliance, capital expenditures, production, cash flow, borrowing base under our Revolving Credit Facility (as defined below), our intention or ability to pay or increase dividends on our capital stock, and impairment are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "continue," "anticipate," "target," "could," "plan," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future production, sales, market size, collaborations, cash flows, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following:

- changes in crude oil and natural gas prices, the pace of drilling and completions activity on our current properties and properties pending acquisition;
- infrastructure constraints and related factors affecting our properties;
- general economic or industry conditions, whether internationally, nationally and/or in the communities in which our company conducts business, including any future economic downturn, cost inflation, supply chain disruptions, the impact of continued or further inflation, disruption in the financial markets, changes in the interest rate environment and actions taken by OPEC and other oil producing countries as it pertains to the global supply and demand of, and prices for, crude oil, natural gas and NGLs;
- ongoing legal disputes over, and potential shutdown of, the Dakota Access Pipeline;
- our ability to identify and consummate additional development opportunities and potential or pending acquisition transactions, the projected capital efficiency savings and other operating efficiencies and synergies resulting from our acquisition transactions, integration and benefits of property acquisitions, or the effects of such acquisitions on our company's cash position and levels of indebtedness;
- changes in our reserves estimates or the value thereof;
- disruption to our company's business due to acquisitions and other significant transactions;
- changes in local, state, and federal laws, regulations or policies that may affect our business or our industry (such as the effects of tax law changes, and changes in environmental, health, and safety regulation and regulations addressing climate change, and trade policy and tariffs);
- conditions of the securities markets;
- risks associated with our Convertible Notes (as defined below), including the potential impact that the Convertible Notes may have on our financial position and liquidity, potential dilution, and that provisions of the Convertible Notes could delay or prevent a beneficial takeover of our company;
- the potential impact of the capped call transactions undertaken in tandem with the Convertible Notes issuance, including counterparty risk;
- increasing attention to environmental, social and governance matters;
- our ability to raise or access capital on acceptable terms;
- cyber-incidents could have a material adverse effect on our business, financial condition or results of operations;
- changes in accounting principles, policies or guidelines;
- events beyond our control, including a global or domestic health crisis, acts of terrorism, political or economic instability or armed conflict in oil and gas producing regions, including the effects of any changes to conditions in or impacting Venezuela;
- other economic, competitive, governmental, regulatory and technical factors affecting our operations, products and prices; and
- other factors discussed in this Annual Report on Form 10-K under "Risk Factors," as updated by any subsequent Forms 10-Q, which are on file with the United States Securities and Exchange Commission (the "SEC").

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in the section entitled "Item 1A. Risk Factors" and other sections of this report, as updated by subsequent reports we file with the SEC, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Readers are urged not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. We assume no obligation to update any forward-looking statements in order to reflect any event or circumstance that may arise after the date of this report, other than as may be required by applicable law or regulation. Readers are urged to carefully review and consider the various disclosures made by us in our reports filed with the SEC which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operation and cash flows. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, our actual results may vary materially from those expected or projected.

Summary of Risk Factors

We believe that the risks associated with our business, and consequently the risks associated with an investment in our equity or debt securities, fall within the following categories:

- **Risks Related to Our Business and the Oil, Natural Gas and NGL Industry**
    - As a participant in the oil and gas industry, there are many risks inherent in our primary business operations. These risks are not necessarily unique to us. Rather, these are risks that most participants in our industry have at least some exposure to and relate to matters such as: drilling and completion operations; reserves estimates; gathering, processing, marketing and transportation; weather and seasonality, including the physical effects of climate change; hedging and commodity price derivatives; and information technology and cybersecurity.
    - Given that our primary source of revenue is the sale of oil, natural gas and NGLs, one of our most material risks is the commodity market and the prices of oil, natural gas and NGLs, which are often volatile.
    - As a non-operator, we have only participated in wells operated by third parties, and thus rely extensively on third parties for the success of our business.
    - Our acquisition strategy subjects us to risks relating to evaluation, integration and growth in connection with past and potential future acquisitions.

- **Risks Related to Our Financing and Indebtedness**
    - Our operations are capital intensive. Pressures on the market as a whole, or our specific financial position – whether due to depressed commodity prices, our leverage, our credit ratings or otherwise – could make it difficult for us to obtain the funding necessary to conduct our operations.
    - Our existing and future debt obligations carry risks related to liquidity, operating and financial restrictions, debt service obligations, and related matters.
    - The capped call transactions may affect the value of the Convertible Notes and our common stock.
    - We are subject to counterparty performance risk with respect to the capped call transactions.
    - The Convertible Notes may have a material effect on our reported financial results.
    - The conditional conversion feature of the Convertible Notes, if triggered, may adversely affect our financial condition and operating results.

- **Risks Related to Legal, Regulatory and Environmental Matters**
    - There are many environmental, energy, financial, real property and other regulations that we and/or third-party operators of our wells are required to comply with in the context of conducting our operations, and we may be exposed to fines, penalties, investigations, litigation or other legal proceedings.
    - Negative public perception of the oil and natural gas industry, future climate change legislation or regulation, increasing consumer demand for alternatives to oil and natural gas, or other climate-related transition risks could adversely impact our earnings, cash flows and financial position.

- **Risks Related to Our Common Stock**
    - Our capital structure, as well as our certificate of incorporation, bylaws, and Delaware state law, subject our stockholders to risk of ownership dilution, loss of market value, and other risks.
    - Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual

restrictions applying to the payment of dividends and other considerations. Investors may be forced to rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

We describe these and other risks in much greater in the section entitled "Item 1A. Risk Factors."

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

<u>Terms used to describe quantities of crude oil and natural gas:</u>

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

"*Boe*." A barrel of oil equivalent and is a standard convention used to express crude oil, NGL and natural gas volumes on a comparable crude oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil or NGL.

"*Boepd.*" Boe per day.

"*Bopd.*" Barrel of oil per day.

"*Btu" or "British Thermal Unit*." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBoe*." One thousand Boe.

"*Mcf*." One thousand cubic feet of natural gas.

"*MMBbl*." One million barrels of crude oil, condensate or NGLs.

"*MMBoe*." One million Boe.

"*MMBtu*." One million British Thermal Units.

"*MMcf*." One million cubic feet of natural gas.

"*NGLs*." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

<u>Terms used to describe our interests in wells and acreage:</u>

"*Basin*." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion.*" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

"*Conventional play.*" An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"*Developed acreage.*" Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Development well.*" A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of a stratigraphic horizon (rock layer or formation) known to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"*Differential.*" The difference between a benchmark price of crude oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

"*Dry hole*." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Exploratory well.*" A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

"*Extension well*." An extension well is a well drilled to extend the limits of a known reservoir.

"*Field*." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*." A layer of rock which has distinct characteristics that differs from nearby rock.

"*Gross acres" or "Gross wells.*" The total acres or wells, as the case may be, in which a working interest is owned.

"*Held by operations.*" A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"*Held by production.*" A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"*Hydraulic fracturing*." The technique of improving a well's production by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"*Infill well.*" A subsequent well drilled in an established spacing unit of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Net acres.*" The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"*Net well.*" A well that is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"*NYMEX*." The New York Mercantile Exchange.

"*OPEC.*" The Organization of Petroleum Exporting Countries.

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

"*Recompletion*." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

"*Service well.*" A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"*Spacing*." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.
"*Stratigraphic test well.*" A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

"*Unconventional play.*" An area believed to be capable of producing crude oil, NGLs, and/or natural gas occurring in cumulations that are regionally extensive but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as this is the case with crude oil and natural gas shale, tight crude oil and natural gas sands and coal bed methane.

"*Undeveloped acreage*." Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

"*Unit*." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*West Texas Intermediate or WTI.*" A light, sweet blend of oil produced from the fields in West Texas.

"*Working interest*." The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"*Workover.*" Operations on a producing well to restore or increase production.

Terms used to assign a present value to or to classify our reserves:

"*Developed Oil and Gas Reserves*." Oil and natural gas reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

"*Possible reserves.*" The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

"*Pre-tax PV-10%" or "PV-10.*" The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

"*Probable reserves.*" The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

"*Proved developed non-producing reserves (PDNPs).*" Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"*Proved developed producing reserves (PDPs).*" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

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

(i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil, NGLs or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"*Proved undeveloped drilling location.*" A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*." Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir or an analogous reservoir.

"*Reserves.*" Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

“*Standardized measure*.” Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

“*Undeveloped Oil and Gas Reserves.*” Oil and natural gas reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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FOR FISCAL YEAR ENDED DECEMBER 31, 2025
PART I

Item 1. *Business*

Overview

We are an independent energy company engaged as a non-operator in the acquisition, exploration, development and production of oil and natural gas properties in the United States, primarily in the Williston Basin, the Permian Basin, the Appalachian Basin and the Uinta Basin. We believe the location, size and concentration of our acreage positions in some of North America's leading unconventional oil and gas resource plays provide us with drilling and development opportunities that will result in significant long-term value. We currently report a single reportable segment. See "Financial Statements" and the notes to our financial statements for financial information about this reportable segment.

Our primary strategy is to invest in non-operated minority working and mineral interests in oil and natural gas properties, with a core area of focus in the premier basins within the United States. As a non-operator, we are able to diversify our investment exposure by participating in a large number of gross wells, as well as entering into additional project areas by partnering with numerous experienced operating partners or pursuing value enhancing acquisitions. In addition, because we can generally elect to participate on a well by well basis, we believe we have increased flexibility in the timing and amount of our capital expenditures because we are not burdened with various contractual arrangements with respect to minimum drilling obligations. Further, we are able to avoid exploratory and infrastructure costs incurred by many oil and natural gas producers.

We seek to create value through strategic acquisitions and financially participating alongside operators who have significant experience in developing and producing hydrocarbons in our core areas. We have more than 100 experienced operating partners that provide technical insights and opportunities for acquisitions. Across these operators, no single operator represented more than 11% of our fourth quarter 2025 oil and natural gas sales.

Prior to 2020, we focused our operations exclusively on oil-weighted properties in the Williston Basin. Since then we have significantly grown and diversified our properties via acquisitions of oil and natural gas properties in the Permian Basin, Appalachian Basin and Uinta Basin. See Note 3 to our financial statements for information regarding our recent acquisition activities. Our acquisition activities were a significant driver of our 6% production growth from 131,777 Boe per day in the fourth quarter of 2024 to 140,064 Boe per day in the fourth quarter of 2025.

The following table provides a summary of certain information regarding our assets as of December 31, 2025, including reserves information audited by our third-party independent reserve engineers, Cawley, Gillespie & Associates, Inc. ("Cawley").

	As of December 31, 2025						
	Net Acres	Productive Wells Gross	Productive Wells Net	Average Daily Production[1] (MBoe per day)	Proved Reserves (MBoe)	% Oil	% Proved Developed
Williston Basin	177,656	8,573	682.5	41.3	104,403	68 %	84 %
Permian Basin	45,767	2,229	349.6	58.5	146,008	56	70
Appalachian Basin	62,198	518	114.2	29.6	99,623	1	80
Uinta Basin	16,176	382	49.1	10.7	34,034	90	40
Total	301,797	11,702	1,195.4	140.1	384,068	48 %	74 %

(1) Represents the average daily production over the three months ended December 31, 2025.

Business Strategy

Our business strategy is focused on growing our reserves, production and free cash flow to create long-term value for our stakeholders while maintaining a strong balance sheet. The key elements of our business strategy include the following:

- *Diversify Our Risk Through Non-Operated Participation in a Large Number of Wells and Multiple Basins*. As a non-operator, we seek to diversify our investment and operational risk through participation in a large number of oil and gas wells and with multiple operators across multiple basins. As of December 31, 2025, we have participated in 11,702 gross (1,195 net) producing wells with an average working interest of 10.2% in each gross well, with more than 100 experienced operating partners. We also believe that we can further diversify our risk with acquisitions in multiple basins, focusing on accretive acquisitions of top-tier assets with top-tier operators in the premier basins in the United States. For the three months ended December 31, 2025, 42% of our production was from the Permian Basin, 30% was from the Williston Basin, 21% was from the Appalachian Basin and 7% was from the Uinta Basin.

- *Accelerate Growth by Pursuing Value-Enhancing Acquisitions.* We strive to be the natural consolidator and clearing house of non-operated working interests in various leading oil and gas shale plays in the United States. Our "ground game" acquisition strategy is to build a strong presence in our core basins and seek to acquire smaller additional lease positions at a significant discount to the contiguous acreage positions typically sought by larger producers and operators of oil and gas wells, focusing on near term drilling opportunities. Such acquisitions have been a significant driver of our net well additions and production growth. We intend to continue these activities, while at the same time evaluating and pursuing larger non-operated asset packages that we believe can responsibly add significant production, cash flow and scale to existing operations.

- *Build and Maintain a Strong Balance Sheet and Proactively Manage to Limit Downside Risk.* We strive for financial strength and flexibility through the prudent management of our balance sheet. Changes in commodity prices, as well as the timing of various investment and financing opportunities, result in changes to our leverage over time. However, we manage the business with the long-term goal of maintaining leverage at or near our target of 1.0x Debt / Adjusted EBITDA.

- *Systematic Hedging Strategy.* Given the volatility of the commodity price environment, we employ an active commodity price risk management program to better enable us to execute our business plan over the entire commodity price cycle. We have a rolling target of hedging 65% or more of our anticipated next 18-month production.

- *Stockholder Returns*. The foregoing strategies are collectively aimed at building a diversified, low-leverage, cash generating business that can deliver meaningful returns to our investors. We have provided stockholder returns in the form of cash dividends and security repurchases, and will seek to grow stockholder returns over time.

Industry Operating Environment

The oil and natural gas industry is a global market impacted by many factors, such as government regulations, particularly in the areas of trade sanctions, taxation, energy, climate change and the environment, geopolitical instability and armed conflicts (including between Russia and Ukraine and in the Middle East), demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

Oil and natural gas prices have been, and we expect may continue to be, volatile. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may affect planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and gas prices may also reduce the amount of our borrowing base under our Revolving Credit Facility, which is determined at the discretion of the lenders based on various factors including the collateral value of our proved reserves. While lower commodity prices may reduce our future net cash flow from operations, we expect to have sufficient liquidity to continue development of our oil and natural gas properties. In addition, we undertake an active commodity hedging program that is designed to help stabilize the volatile commodity pricing environment and protect cash flows in a potential downturn.

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Additionally, ongoing inflationary pressures have resulted in and may result in additional increases to the costs of goods, services and personnel. Material changes in prices impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Sustained levels of high inflation caused the U.S. Federal Reserve to increase the federal funds interest rate by 5.25% to a high of 5.375% between March 2022 and July 2023 in an effort to curb inflationary pressure on the costs of goods and services. While inflationary pressures in the United States' economy have begun to subside, inflation is still holding above the U.S. Federal Reserve's target level. Further, despite the U.S. Federal Reserve decreasing the federal funds interest rate to 3.625% between September 2024 and December 2025, we continue to be impacted by the elevated federal funds interest rate, which could additionally have the effects of raising the cost of capital and depressing economic growth.

Development

As a non-operator, we primarily engage in oil and natural gas exploration and production by participating on a proportionate basis alongside third-party interests in wells drilled and completed in spacing units that include our acreage. In addition, we acquire wellbore-only working interests in wells in which we do not hold the underlying leasehold interests from third parties unable or unwilling to participate in particular well proposals. We typically depend on drilling partners to propose, permit and initiate the drilling of wells. Prior to commencing drilling, our partners are required to provide all owners of oil, natural gas and mineral interests within the designated spacing unit the opportunity to participate in the drilling costs and revenues of the well to the extent of their pro-rata share of such interest within the spacing unit. We assess each drilling opportunity on a case-by-case basis and participate in wells that we expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and natural gas, expected oil and gas prices, expertise of the operator, and completed well cost from each project, as well as other factors. Historically, we have participated pursuant to our working interest in a vast majority of the wells proposed to us. However, declines in oil prices typically reduce both the number of well proposals we receive and the proportion of well proposals in which we elect to participate. Our land and engineering team uses our extensive database to make these economic decisions. Given our large acreage footprint and substantial number of well participations, we believe we can make accurate economic decisions with respect to our participation in well proposals.

Historically, we have not managed our commodities marketing activities internally. Instead, our operating partners generally market and sell oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our oil and gas production from our wells to appropriate pipelines or rail transport facilities pursuant to arrangements that they negotiate and maintain with various parties purchasing the production. We understand that our partners generally sell our production to a variety of purchasers at prevailing market prices under separately negotiated short-term contracts. Although we have historically relied on our operating partners for these activities, we may in the future seek to take a portion of our production in kind and internally manage the marketing activities for such production. The price at which our production is sold is generally tied to the spot market for oil or natural gas. The price at which our oil production is sold typically reflects a discount to the NYMEX benchmark price. This differential primarily represents the transportation costs in moving the oil from wellhead to refinery and will fluctuate based on availability of pipeline, rail and other transportation methods. The price at which our natural gas production is sold may reflect either a discount or premium to the NYMEX benchmark price. Using our commodity hedging program, from time to time we enter into financial hedging contracts to help mitigate pricing risk and volatility with respect to differentials.

Competition

The oil and natural gas industry is intensely competitive and we compete with numerous other oil and natural gas exploration and production companies, many of which have substantially greater resources than we have and may be able to pay more for exploratory prospects and productive oil and natural gas properties. Our larger or integrated competitors may be better able to absorb the burden of existing, and any changes to, federal, state, and local laws and regulations than we can, which would adversely affect our competitive position. Our ability to add reserves and acquire additional properties in the future is dependent upon our ability and resources to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Marketing and Customers

The market for oil and natural gas that will be produced from our properties depends on many factors, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of pipelines and other transportation and storage facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners include a variety of exploration and production companies, from large publicly-traded companies to small, privately-owned companies. We do not believe the loss of any single operator would have a material adverse effect on our company as a whole.

Title to Properties

Our oil and natural gas properties are subject to customary royalty and other interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our indebtedness under our Revolving Credit Facility is also secured by liens on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory title to or rights in our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title only when we acquire producing properties or before commencement of drilling operations.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt the drilling and producing activities of our operating partners and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt the operations of our operating partners and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operating partners' operations.

Principal Agreements Affecting Our Ordinary Business

We generally do not own physical real estate, but, instead, our acreage is primarily comprised of leasehold interests subject to the terms and provisions of lease agreements that provide our company the right to participate in drilling and maintenance of wells in specific geographic areas. Lease arrangements that comprise our acreage positions are generally established using industry-standard terms that have been established and used in the oil and natural gas industry for many years. Many of our leases are or were acquired from other parties that obtained the original leasehold interest prior to our acquisition of the leasehold interest.

In general, our lease agreements stipulate three-to-five year terms. Bonuses and royalty rates are negotiated on a case-by-case basis consistent with industry standard pricing. Once a well is drilled and production established, the leased acreage in the applicable spacing unit is considered developed acreage and is held by production. Other locations within the drilling unit created for a well may also be drilled at any time with no time limit as long as the lease is held by production. Given the current pace of drilling in the areas of our operations, we do not believe lease expiration issues will materially affect our acreage position.

Governmental Regulation and Environmental Matters

Our business is subject to various rules, regulations and limitations impacting the oil and natural gas exploration and production industry as whole.

Regulation of Oil and Natural Gas Production

The oil and natural gas exploration, production and related operations that we participate in as a non-operator are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, many states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which our operating partners can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. The current price index covers the five-year period which commenced on July 1, 2021.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

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

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Interstate transportation services, however, remain subject to FERC regulation, including with respect to rates, terms and conditions of service, and authorizations to build new, or abandon old, facilities. A primary aim of FERC's regulation of interstate natural gas transportation is to prevent undue discrimination among shippers, and so we do not anticipate that FERC regulation will affect our operations in any way that is materially different from those of similarly situated competitors.

Onshore gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state, tribal and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. These laws and regulations may:

- require the acquisition of a permit or other authorization and procurement of financial assurance before construction or drilling commences and for certain other activities;
- limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act (“CERCLA”) and comparable state statutes impose strict, joint and several liability on several categories of persons, including current and former owners and operators of sites and on persons who disposed of or arranged for the disposal of “hazardous substances” found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes govern the disposal of “solid waste” and “hazardous waste” and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of “hazardous substance,” state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as “non-hazardous” if properly handled, such exploration and production wastes could be reclassified in the future as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. Recent regulation and litigation that has been brought against others in the industry under RCRA concern liability for earthquakes that were allegedly caused by injection of oil field wastes.

The Endangered Species Act (“ESA”) seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or its habitat. Accordingly, restrictions may be imposed on exploration and production operations, as well as actions by federal agencies, to avoid significantly impairing or jeopardizing the species or its habitat. The ESA provides for criminal penalties for willful violations of the ESA. The U.S. Fish and Wildlife Service must also designate the species’ critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. However, in April 2025, the U.S. Fish and Wildlife Service and National Marine Fisheries Service proposed to redefine “harm” to mean affirmative acts that are directed immediately and intentionally against a particular animal, excluding acts or omissions that indirectly cause injury. Additionally, in November 2025, the Trump Administration proposed several rules that would significantly alter ESA protections for plants and animals. One proposed rule would rescind a rule that automatically extends protections for endangered species to threatened species. Another proposed rule would change regulations for listing species as endangered or threatened as well as for designating critical habitats. Additionally, a third proposed rule would reinstate the framework for evaluating the benefits and cost of designating a critical habitat by considering factors like economic impact, impact on national security, and other relevant impacts. The U.S. Fish and Wildlife Service is expected to issue final rules in 2026. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations are in substantial compliance with such statutes, future amendments are uncertain, and any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our operating partners) to significant expenses to modify our operations or could force discontinuation of certain operations altogether. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

The Clean Air Act ("CAA") controls air emissions from oil and natural gas production and natural gas processing operations, among other sources. CAA regulations include New Source Performance Standards ("NSPS") for the oil and natural gas source category to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities.

In November 2021, the Environmental Protection Agency ("EPA") issued a proposed rule intended to revise and add to the NSPS program rules, known as Subpart OOOOa. The proposed rule sought to formally reinstate methane (a greenhouse gas ("GHG")) emission limitations for existing and modified facilities in the oil and gas sector under Subparts OOOOa and OOOOb and sought to also regulate existing oil and gas facilities for the first time. Under Subpart OOOOc, the EPA's proposed rule sought to require states to implement plans that meet or exceed federally established emission reduction guidelines for existing oil and natural gas facilities. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule sought to remove an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring system to flag large emissions events, referred to in the proposed rule as "super emitters." In December 2023, the EPA announced a final rule, later published in March 2024, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance deadlines under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, until March 2026 to develop and submit their plans for reducing methane emissions from existing sources. However, in March 2025, the EPA announced its intention to reconsider the March 2024 rule, including Subparts OOOOb and OOOOc, with a final rule expected in or around July 2026. A subsequent rule, finalized on November 26, 2025, gives states, along with federal tribes that wish to regulate existing sources, until January 2027 to develop and submit their plans for reducing methane emissions from existing sources. Additionally, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of these rules remains uncertain at this time. At the same time, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. Any regulations or proposals requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations and financial condition.

At the international level, the United Nations-sponsored Paris Agreement requires signatory countries to set voluntary targets to reduce domestic GHG emissions. While the United States withdrew from the Paris Agreement during the Trump Administration in 2020, the Biden Administration recommitted the United States to the Paris Agreement in January 2021 and established a goal of reducing GHG emissions by at least fifty percent from 2005 levels by 2030. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change. Additionally, in January 2026, the Trump Administration announced the formal withdrawal of the United States from the United Nations Framework Convention on Climate Change in a presidential memorandum. The full impact of these actions remains unclear at this time. At the same time, various state and local governments have publicly committed to furthering the goals of the Paris Agreement and, many related initiatives are expected to continue at the local, state and international levels.

The Federal Water Pollution Control Act of 1972, or the Clean Water Act (the "CWA"), imposes restrictions and controls on the discharge of produced waters and other pollutants into waters of the United States ("WOTUS"). Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. CWA jurisdiction depends on the definition of WOTUS. In January 2023, the EPA and the U.S. Army Corps of Engineers (the "USAC") issued a final rule that based the definition of WOTUS on a pre-2015 definition, which never took effect before being replaced in 2020. Separately, in May 2023, the U.S. Supreme Court's decision in Sackett v. EPA narrowed federal jurisdiction over wetlands to "traditional navigable waters" and wetlands or other waters that have a "continuous surface connection" with or are otherwise indistinguishable from traditional navigable water. In September 2023, the EPA and the Corps published a direct-to-final rule that conforms the regulatory definition of WOTUS to the Supreme Court's May 2023 decision in Sackett. However, roughly half of the states and other plaintiffs are challenging the September 2023 rule, and the EPA and the Corps are using the pre-2015 definition of WOTUS in these states while litigation continues. In November 2025, the Corps and the EPA proposed another rule revising the definition of WOTUS to conform to the Supreme Court's decision in Sackett by providing clarity on terms such as "relatively permanent," "tributary," and "continuous surface connection." As a result, substantial uncertainty exists with respect to future implementation of the September 2023 rule and the scope of CWA jurisdiction more generally. Any expansion to CWA jurisdiction could impact areas where oil and gas operations are conducted. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. In 2021, the United States Supreme Court held that the CWA requires a discharge permit if the addition of pollutants through groundwater is the functional equivalent of a direct discharge from the point source into navigable waters. In November 2023, the EPA issued draft guidance describing the information that should be used to determine which discharges through groundwater may require a permit. However, in January 2025, President Trump issued executive orders directing (i) the EPA and the Corps to identify planned or potential actions that could be subject to emergency treatment under Section 404 of the CWA and (ii) the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions, including all existing regulations and guidance documents, that are unduly burdensome on the identification, development, or use of domestic energy resources. Accordingly, on January 15, 2026, the EPA published a proposed rule to revise the Section 401 state and tribal water quality certification regulations. The proposed rule aims to narrow the "activity"-based scope of state and tribal certification to point source discharges into waters of the United States. The public comment period concludes on February 17, 2026. Future implementation and enforcement of these rules and policies is uncertain at this time. Additionally, costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans.

The CAA, CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

The underground injection of oil and natural gas wastes is regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act and programs under comparable state statutes. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Substantially all of the oil and natural gas production in which we have interest is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed but not passed in recent sessions of Congress. The EPA has issued guidance on permitting hydraulic fracturing that uses fluids containing diesel fuel under the Underground Injection Control ("UIC") program, specifically as "Class II" UIC wells, and prohibits the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants.

Scrutiny of hydraulic fracturing activities continues in other ways. The federal government continues to study hydraulic fracturing's potential impacts. Several states, including states where we have properties, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have attempted to enact bans on hydraulic fracturing. We cannot predict whether any other legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, it could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our revenue and results of operations.

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA. Many of the activities of our third-party operating partners are covered under NEPA. Some activities are subject to robust NEPA review which could lead to delays and increased costs that could materially adversely affect our revenues and results of operations. Other activities are covered under categorical exclusions which results in a shorter NEPA review process. In April 2022, the White House Council on Environmental Quality ("CEQ") finalized the first of two planned rules to undo changes to NEPA enacted in 2020 under the Trump Administration. The Phase I Final Rule generally restores certain regulatory provisions that were in effect prior to the 2020 rule, affecting the assessment of projects ranging from oil and gas leasing to development on public and Indian lands. Additionally, in September 2023, the Biden Administration announced that federal agencies will be directed to consider the Social Cost of GHGs in agency budgeting, procurement, and other agency decisions, including in environmental reviews conducted pursuant to NEPA, where appropriate. In May 2024, CEQ finalized the Phase II rule, which generally restores certain mitigation language from the pre-2020 version of the NEPA regulations, proposes further revisions, and meets environmental, environmental justice, and climate change objectives. However, at least twenty states challenged the Phase II rule in federal district court. In January 2025, President Trump issued executive orders directing (i) CEQ to provide guidance on implementing NEPA and to propose rescinding and replacing CEQ's NEPA regulations with implementing regulations at the agency level; (ii) federal agencies to adhere to only the relevant legislated requirements for environmental reviews and to prioritize efficiency and certainty over any other objectives in such reviews; and (iii) the EPA to issue guidance on and consider eliminating the Social Cost of GHG calculation from federal permitting or regulatory decisions. In February 2025, CEQ sent an interim final rule to the White House Office of Management and Budget that would immediately withdraw the NEPA implementing regulations. In January 2026, CEQ formally repealed its NEPA implementing regulations on the basis of the Supreme Court's decision in *Seven County Infrastructure Coalition v. Eagle County, Colorado*. In *Seven County*, the Supreme Court directed lower courts to give "substantial deference" to reasonable agency conclusions underlying its NEPA process. Accordingly, the January 2026 rule is meant to streamline NEPA review, and has left the July 2020, Phase I, and Phase 2 rules in place. The January 2026 rule may be subject to litigation. Congress is also considering legislation designed to streamline NEPA through the Standardizing Permitting and Expediting Economic Development Act ("SPEED Act"). The SPEED Act aims to redefine what qualifies as a "major Federal action" and impose stricter deadlines for NEPA review. The SPEED Act has passed the House of Representatives and passage remains pending and uncertain. The potential impact of further changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our business and operations.

Climate Change

In the United States, no comprehensive federal climate change legislation regulating GHG emissions or directly imposing a price on carbon has been implemented to date; however, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. These include the Paris Agreement, a treaty adopted at the 21st United Nations Conference of the parties that is aimed at addressing climate change with member countries agreeing to nationally determine their contributions and set GHG emission reduction goals every five years and the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change. Additionally, in January 2026, the Trump Administration announced the formal withdrawal of the United States from the United Nations Framework Convention on Climate Change in a presidential memorandum. The full impact of these actions remains unclear at this time. At the same time, many state and local leaders have intensified or stated their intent to intensify efforts to support international climate commitments and treaties, in addition to considering or enacting laws requiring the disclosure of climate-related information and developing programs that are aimed at reducing GHG emissions by means of cap and trade programs, carbon taxes or encouraging the use of renewable energy or alternative lower-carbon fuels. Although the Supreme Court's decision in *Loper Bright Enterprises v. Raimondo* to overrule *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.* and end the concept of general deference to regulatory agency interpretations of laws introduces new complexity for federal agencies and administration of climate change policy and regulatory programs, many of these initiatives at the international, state and local levels are expected to continue.

Further, legislative and regulatory initiatives are underway to that purpose. The Inflation Reduction Act of 2022 ("IRA"), signed into law in August 2022, appropriates significant federal funding for renewable energy initiatives and, for the first time ever, imposes a Waste Emissions Charge ("WEC") on GHG emissions from certain oil and gas sources and facilities. To implement the program, in May 2024, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. Among other things, the new rule expands the emissions events that are subject to reporting requirements to include "other large release events" and applies reporting requirements to certain new sources and sectors. The emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the Methane Emissions Reduction Program in the IRA. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. In addition, in November 2024, the EPA finalized a rule to implement the IRA's WEC. However, in January 2025, the Trump Administration issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. In addition, in March 2025, President Trump signed Congress' Joint Resolution of Disapproval of the WEC, and in May 2025, EPA issued a final rule to remove the WEC regulations from the Code of Federal Regulations. In July 2025, the One Big Beautiful Bill Act delayed the effective date of the WEC until 2034.

The U.S. Congress has also considered legislation that would control GHG emissions through a “cap and trade” program and several states have already implemented programs to reduce GHG emissions. Additionally, following the U.S. Supreme Court finding that GHG emissions fall within the CAA definition of an “air pollutant,” the EPA has adopted regulations that, among other things, establish construction and operating permit review for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources, and together with the United States Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. The EPA also finalized rules in December 2023 intended to reduce methane emissions from new and existing oil and gas sources and in January 2024, the Biden Administration announced a temporary pause on pending decisions on exports of liquified natural gas to non-free trade agreement countries until the Department of Energy can update the underlying analyses for authorizations, including an assessment of the impact of GHG emissions. The Department of Energy released its report on liquified natural gas exports in December 2024, which report is subject to a 60-day public comment period ending in February 2025. However, in January 2025, President Trump issued executive orders directing (i) the Department of Energy to restart reviews of applications for approvals of liquefied natural gas export projects as expeditiously as possible; (ii) the EPA and the heads of any other relevant federal agencies to submit joint recommendations to the Office of Management and Budget regarding the continuing applicability of the GHG endangerment finding of 2009; and (iii) the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Additionally, in September 2025, the EPA proposed to permanently remove program obligations from the Greenhouse Gas Reporting Program for most source categories, and suspend program obligations for some sources subject to subpart W (which applies to emission sources in certain segments of the petroleum and natural gas industry) until 2034. The full impact of these orders remains uncertain at this time. At the same time, many state and local leaders have intensified or stated their intent to intensify efforts to support international climate commitments and treaties, in addition to considering or enacting laws requiring the disclosure of climate-related information and developing programs that are aimed at reducing GHG emissions by means of cap and trade programs, carbon taxes or encouraging the use of renewable energy or alternative lower-carbon fuels.

In 2014, Colorado was the first state in the nation to adopt rules to control methane emissions from oil and gas facilities. In 2016, the EPA revised and expanded NSPS, also known as Subpart OOOOa, to include final rules to curb emissions of methane, a GHG, from new, reconstructed and modified oil and gas sources. Previously, already existing NSPS regulated VOCs, and controlling VOCs also had the effect of controlling methane, because natural gas leaks emit both compounds. However, by explicitly regulating methane as a separate air pollutant, the 2016 regulations were a statutory predicate to propose regulating emissions from existing oil and gas facilities. In 2021, the EPA proposed rules to regulate methane emissions from the oil and natural gas industry, including, for the first time, reductions from certain upstream and midstream existing oil and gas sources under Subparts OOOOa and OOOOb. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rules, removing an emissions monitoring exemption for small wellhead-only sites and creating a new third-party monitoring program to flag large emissions events. In December 2023, the EPA announced a final rule, later published in March 2024, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for certain Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance deadlines under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, until March 2026 to develop and submit their plans for reducing methane emissions from existing sources. However, in March 2025, the EPA announced its intention to reconsider the March 8, 2024 rule, including Subparts OOOOb and OOOOc, with a final rule expected in or around July 2026. A subsequent rule, finalized on November 26, 2025, gives states, along with federal tribes that wish to regulate existing sources, until January 2027 to develop and submit their plans for reducing methane emissions from existing sources. The final rule is subject to ongoing litigation but remains in effect. Additionally, in January 2025, the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) finalized a rule that requires pipelines, underground natural gas storage facilities, and liquefied natural gas facilities to update leak detection and repair programs to require companies to use commercially available technologies to find and fix methane leaks from pipelines and other facilities. PHMSA and the Department of Interior continue to focus on regulatory initiatives to control methane emissions from upstream and midstream equipment. To the extent that these regulations or initiatives remain in place and to the extent that our third-party operating partners are required to further control methane emissions, such controls could impact our business. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of these rules remains uncertain at this time.

In addition, our third-party operating partners may be required to report their GHG emissions under CAA rules. Because regulation of GHG emissions continues to evolve, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Moreover, while the U.S. Supreme Court held in its 2011 decision *American Electric Power Co. v. Connecticut* that, with respect to claims concerning GHG emissions, the federal common law of nuisance was displaced by the CAA, the Court left open the question of whether tort claims against sources of GHG emissions alleging property damage may proceed under state common law. There thus remains some litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

Human Capital Resources

As of December 31, 2025, we had 64 full time employees. We may hire additional personnel as appropriate. We may also use the services of independent consultants and contractors to perform various professional services from time to time.

We strive to attract, develop and retain the best talent and spend considerable time and resources to advance the professional development and security of our workforce. We operate on the fundamental philosophy that people are our most valuable asset, as every person who works for us has the potential to impact our success. We believe employees choose to work at the Company in part due to our engaging culture, competitive compensation and benefits, and professional development opportunities. To attract and retain the best talent, we provide our employees a comprehensive total rewards program, including opportunities for share ownership in the Company. In addition to competitive salaries, we offer both short and long-term incentive compensation; company-matched 401(k) contributions; company-paid premiums for health, dental and vision insurance, short and long-term disability insurance, and life insurance; and company-supported health savings accounts and flexible spending accounts. The Company also provides a generous match for employee donations to qualifying charitable organizations, and organizes employee volunteer days from time to time. We offer many additional programs to support the wellness of our workforce, including an onsite fitness center within our executive offices, company-provided lunches, and a flexible paid time off and vacation policy.

We recognize the importance of investing in our employees' professional development and are committed to ensuring that all employees are prepared for every aspect of their day-to-day roles. We have a multi-year rotational analyst development program, to ensure that we are hiring and developing new talent and offering cross-functional exposure and learning experience. This program was designed with the intent of developing an internally trained pool of future leaders that have a holistic view of our systems, processes and operations. We also support employees who seek to further their professional development through appropriate external educational programs and offer tuition reimbursement benefits for various extended educational learning opportunities.

We are committed to providing a workplace environment free of discrimination and harassment, where all individuals are treated with respect and dignity, can contribute fully, and have equal opportunities. We value and strive to treat all employees, consultants, vendors, contractors, service providers, and business partners equally. We prohibit discrimination or harassment on the basis of any grounds prohibited by law. We are committed to maintaining employment practices based on equal opportunity for all employees and providing a safe and productive working environment for all employees. Our policies and practices are designed to promote diversity of thought, perspective, and professional experience, and to support all employees fairly without regard to disability, sexual orientation, gender, gender identity and expression, religion, race, ethnicity, culture, and nationality, among others.

Office Locations

Our executive offices are located at 4350 Baker Road, Suite 400, Minnetonka, Minnesota 55343. Our office space consists of 24,641 square feet of leased space. We believe our current office space is sufficient to meet our needs and that additional office space can be obtained if necessary.

Organizational Background

On May 9, 2018, we filed articles of conversion with the Secretary of State of the State of Minnesota and filed a certificate of conversion with the Secretary of State of the State of Delaware changing our jurisdiction of incorporation from Minnesota to Delaware (the "Reincorporation"). The Reincorporation was approved by our stockholders at a special meeting held on May 8, 2018. Upon the Reincorporation, each outstanding certificate representing shares of the Minnesota corporation's common stock was deemed, without any action by the holders thereof, to represent the same number and class of shares of our company's common stock. As of May 9, 2018, the rights of our stockholders began to be governed by Delaware General Corporation Law (the "DGCL") and our Delaware certificate of incorporation and bylaws.

Available Information – Reports to Security Holders

Our website address is www.noginc.com. We make available on this website, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. Electronic filings with the SEC are also available on the SEC internet website at www.sec.gov.

We have also posted to our website our Bylaws, Acquisition Committee Charter, Audit Committee Charter, Compensation Committee Charter, Executive Committee Charter, Governance, Nominating and ESG Committee Charter, Corporate Governance Guidelines, Stock Ownership Guidelines, Code of Business Conduct and Ethics, Insider Trading Policy, Clawback Policy, Related Person Transaction Approval Policy, ESG Policy, Anti-Corruption and Bribery Policy, Human Rights Statement, Political Contributions and Trade Associations Policy and our Compliance Hotline, in addition to all pertinent company contact information.

We use our website as a channel of distribution for important Company information. We routinely post important information, including presentation materials and press releases, to our corporate website, www.noginc.com, including the investor relations section thereof. We also use our website to expedite public access to time-critical information regarding our Company in advance of or in lieu of distributing a press release or a filing with the SEC disclosing the same information. When permissible, we expect to continue to do so without also providing disclosure of this information through filings with the SEC. Therefore, investors should look to our website for important and time-critical information.

Where we have included Internet addresses in this Annual Report on Form 10-K, we have included those Internet addresses as inactive textual references only. Except as specifically incorporated by reference into this Annual Report on Form 10-K, information on those websites is not part hereof.

Item 1A. ***Risk Factors***

In addition to the other information contained in this Annual Report on Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. Note that additional risks not presently known to us or that are currently considered immaterial may also have a negative impact on our business and operations. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline.

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

Oil and natural gas prices are volatile. Extended declines in oil and natural gas prices have adversely affected, and could in the future adversely affect, our business, financial position, results of operations and cash flow.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. Oil and natural gas prices have fluctuated significantly, including periods of rapid and material decline, in recent years. The prices we receive for our oil and natural gas production heavily influence our production, revenue, cash flows, profitability, reserve bookings and access to capital. Although we seek to mitigate volatility and potential declines in commodity prices through derivative arrangements that hedge a portion of our expected production, this merely seeks to mitigate (not eliminate) these risks, and such activities come with their own risks.

The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of OPEC and other major oil producing countries, such as Russia, relating to oil price and production levels, including announcements of potential changes to such levels;
- worldwide and regional economic, political and social conditions impacting the global supply and demand for oil and natural gas, which may be driven by various risks including war, terrorism, political unrest, or health epidemics;
- the price and quantity of imports of foreign oil and natural gas;
- the uncertainty in capital and commodities markets and the ability of oil and gas producers to access capital;
- increased focus by the investment community on sustainability practices in the oil and natural gas industry;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, including the effects of any changes to conditions in or impacting Venezuela;
- the outbreak of military hostilities, including the ongoing conflict between Russia and Ukraine and the destabilizing effect such conflict continues to pose for the European continent or the global oil and natural gas markets, as well as the ongoing conflict in Israel and the surrounding region;
- the level of global oil and natural gas exploration, production activity and inventories;
- changes in U.S. energy policy;
- weather conditions, chronic and acute climatic events associated with the effects of global climate change, and outbreak of disease;
- technological advances affecting energy consumption;
- the development, exploitation and market acceptance of alternative energy sources as part of a transition to a lower carbon economy;
- domestic and foreign governmental taxes, tariffs and/or regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas; and
- the price and availability of alternative fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict oil and natural gas prices. A substantial or extended decline in oil or natural gas prices, such as the significant and rapid decline that occurred in 2020, has resulted in and could result in future impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we may be required to reduce spending or borrow or issue additional equity to cover any such shortfall. Lower oil and natural gas prices may limit our ability to comply with the covenants under our Revolving Credit Facility (or other debt instruments) and/or limit our ability to access borrowing availability thereunder, which is dependent on many factors including the value of our proved reserves.

Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

Our operators' drilling activities are subject to many risks, including the risk that they will not discover commercially productive reservoirs. Drilling for oil or natural gas can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, drilling and producing operations on our acreage may be curtailed, delayed or canceled by our operators as a result of other factors, including:

- declines in oil or natural gas prices;
- infrastructure limitations, such as gas gathering and processing constraints;
- the high cost, shortages or delays of equipment, materials and services;
- unexpected operational events, pipeline ruptures or spills, adverse weather conditions, facility malfunctions or title problems;
- compliance with environmental and other governmental requirements;
- regulations, restrictions, moratoria and bans on hydraulic fracturing;
- unusual or unexpected geological formations;
- environmental hazards, such as oil, natural gas or well fluids spills or releases, pipeline or tank ruptures and discharges of toxic gas;
- fires, blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids; and
- pipeline capacity curtailments.

In addition to causing curtailments, delays and cancellations of drilling and producing operations, many of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties. We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Lower oil and natural gas prices and other factors have resulted in significant writedowns of our oil and natural gas properties, and we may be required to record further writedowns of our oil and natural gas properties in the future.

We follow the full cost method of accounting for our oil and gas operations. Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, an impairment would be recognized. Such write-downs do not impact cash flows from operating activities but do reduce net income. For the year ended December 31, 2025, we recorded a non-cash full cost ceiling impairment charge of $702.7 million. Depending on future commodity price levels, the trailing twelve-month average price used in the ceiling calculation may decline, which could cause additional future write downs of our oil and natural gas properties. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods.

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

Determining the amount of oil and natural gas recoverable from various formations involves significant complexity and uncertainty. No one can measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating, exploration and development costs. Some of our reserve estimates are made without the benefit of a lengthy production history and are less reliable than estimates based on a lengthy production history. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate.

We routinely make estimates of oil and natural gas reserves in connection with managing our business and preparing reports to our lenders and investors, including in some cases estimates prepared by our internal reserve engineers and professionals that are not reviewed or audited by an independent reserve engineering firm. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, development schedules, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, reserve engineers and other advisors to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based result in the actual quantities of oil, natural gas and NGLs we ultimately recover being different from our reserve estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K, subsequent reports we file with the SEC or other company materials.

Our future success depends on our ability to replace reserves that our operators produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and derive production from additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, participate in successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as our reserves are produced. We have added significant net wells and production from wellbore-only acquisitions, where we don't hold the underlying leasehold interest that would entitle us to participate in future wells. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We may acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We seek to acquire both proved and producing properties as well as undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all of these properties will contain economically viable reserves or that we will not abandon our initial investments. Additionally, we cannot assure you that unproved reserves or undeveloped acreage that we acquire will be profitably developed, that new wells drilled on our properties will be productive or that we will recover all or any portion of our investments in our properties and reserves.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

We base the estimated discounted future net cash flows from our proved reserves on specified pricing and cost assumptions. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as the volume, pricing and duration of our oil and natural gas hedging contracts; actual prices we receive for oil, natural gas and NGLs; our actual operating costs in producing oil, natural gas and NGLs; the amount and timing of our capital expenditures; the amount and timing of actual production; and changes in governmental regulations or taxation. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our business depends on third-party transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, growth in demand outpacing growth in capacity, physical damage, scheduled maintenance, legal or other reasons such as suspension of service due to legal challenges (see below regarding the Dakota Access Pipeline), could result in a substantial increase in costs, declines in realized commodity prices, the shut-in of producing wells or the delay or discontinuance of development plans for our properties. In recent periods, we experienced significant delays and production curtailments, and declines in realized natural gas prices, that we believe were due in part to gas gathering and processing constraints in the Williston Basin. The negative effects arising from these and similar circumstances may last for an extended period of time. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, our wells may be drilled in locations that are serviced to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we rely on third-party oil trucking to transport a significant portion of our production to third-party transportation pipelines, rail loading facilities and other market access points. In addition, concerns about the safety and security of oil and gas transportation by pipeline may result in public opposition to pipeline development and increased regulation of pipelines by PHMSA, and therefore less capacity to transport our products by pipeline.

The Dakota Access Pipeline ("DAPL"), a major pipeline transporting crude oil from the Williston Basin, is subject to ongoing litigation (the "DAPL Litigation") that could threaten its continued operation. In July 2020, a federal district court ordered DAPL to be shut down pending the completion of an environmental impact statement ("EIS") to determine whether the DAPL poses a threat to the Missouri River and drinking water supply of the Standing Rock Sioux Reservation. The temporary shutdown order was overturned by the U.S. Court of Appeals in August 2020. DAPL currently remains in operation while the USACE conducts the EIS, which was released in draft form in September 2023 and was open for public comment until mid-December 2023. The USACE received over 200,000 public comments. On December 19, 2025, the USACE completed the final EIS. Following this completion of the EIS, the USACE will determine whether to grant DAPL an easement to cross the Missouri River or to shut down the pipeline. Publication of the EIS does not constitute a decision, and a subsequent 30-day waiting period is required. After the waiting period, which concluded on January 20, 2026, the USACE may issue a Record of Decision identifying a selected alternative for implementation. Moreover, the EIS and/or the USACE's easement decision may subsequently be challenged in court. In March 2025, a 2024 challenge to the ongoing operation of the pipeline was dismissed in the D.C. Circuit. Petitioners have filed an appeal and litigation is ongoing. As a result, a shut-down remains possible, and there is no guarantee that DAPL will be permitted to continue operations following the completion of the EIS and/or the DAPL Litigation. Any significant curtailment in gathering system or pipeline capacity, or the unavailability of sufficient third-party trucking or rail capacity, could adversely affect our business, results of operations and financial condition.

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

A significant portion of our acreage is not currently held by production or held by operations. Unless production in paying quantities is established or operations are commenced on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to participate in the development of the related properties. Drilling plans for these areas are generally in the discretion of third-party operators and are subject to change based on various factors that are beyond our control, such as: the availability and cost of capital, equipment, services and personnel; seasonal conditions; regulatory and third-party approvals; oil, NGL and natural gas prices; results of title work; gathering system and other transportation constraints; drilling costs and results; and production costs. As of December 31, 2025, we estimate that we had leases that were not developed that represented 1,899 net acres potentially expiring in 2026, 2,727 net acres potentially expiring in 2027, 3,239 net acres potentially expiring in 2028, 2,676 net acres potentially expiring in 2029, and 8,564 net acres potentially expiring in 2030 and beyond.

Seasonal weather conditions adversely affect operators' ability to conduct drilling activities in some of the areas where our properties are located.

Seasonal weather conditions can limit drilling and producing activities and other operations in some of our operating areas and as a result, a significant portion of the drilling on our properties is generally performed during the summer and fall months. These seasonal constraints can pose challenges for meeting well drilling objectives and increase competition for equipment, supplies and personnel during the summer and fall months, which could lead to shortages and increase costs or delay operations. Additionally, many municipalities impose weight restrictions on the paved roads that lead to jobsites due to the muddy conditions caused by spring thaws. This could limit access to jobsites and operators' ability to service wells in these areas.

We are subject to physical risks arising from climate change, which may have a negative impact on our business and results of operations.

Most scientists have concluded that increasing concentrations of GHG in the earth's atmosphere may produce significant physical effects on weather conditions, such as increased frequency and severity of storms, extreme temperatures, droughts and floods, among other climatic phenomena. If any such effects were to occur, they could adversely affect or delay demand for oil and natural gas products or cause us or our third party operators to incur significant costs in preparing for, or responding to, the effects of climatic events themselves, which may not be fully insured. Energy needs could increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate changes. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. To the extent the frequency of extreme weather events increases, this could impact our business in various ways, including damage to operators' facilities at our properties or increased insurance premiums and reduced availability of insurance coverage. Potential adverse effects on our third party operators could also include disruption of their production activities and supply chain. Any of these effects could have an adverse effect on our business, results of operations and financial condition.

As a non-operator, our development of successful operations relies extensively on third parties, which could have a material adverse effect on our results of operation.

We have only participated in wells operated by third parties. The success of our business operations depends on the timing of drilling activities and success of our third-party operators. If our operators are not successful in the development, exploitation, production and exploration activities relating to our leasehold interests, or are unable or unwilling to perform, our financial condition and results of operation would be materially adversely affected.

These risks are heightened in a low commodity price environment, which may present significant challenges to our operators. The challenges and risks faced by our operators may be similar to or greater than our own, including with respect to their ability to service their debt, remain in compliance with their debt instruments and, if necessary, access additional capital. Commodity prices and/or other conditions have in the past and may in the future cause oil and gas operators to file for bankruptcy. The insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator's breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs because of its insolvency or otherwise, to require us to pay our proportionate share of the defaulting party's share of costs.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations to other owners of working interests), which may not be in our best interests. We may have no ability to exercise influence over the operational decisions of our operators, including the setting of capital expenditure budgets and drilling locations and schedules. Dependence on our operators could prevent us from realizing our target returns for those locations. The success and timing of development activities by our operators will depend on a number of factors that will largely be outside of our control, including oil and natural gas prices and other factors generally affecting the industry operating environment; the timing and amount of capital expenditures; their expertise and financial resources; approval of other participants in drilling wells; selection of technology; and the rate of production of reserves, if any.

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

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production, which operating partners market on our behalf to energy marketing companies, refineries and their affiliates. We are subject to credit risk due to the concentration of our oil and natural gas receivables with a limited number of operating partners. This concentration may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. A low commodity price environment may strain our operating partners, which could heighten this risk. The inability or failure of our operating partners to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Inflationary pressure and associated changes in monetary policy have resulted in and may result in additional increases to the cost of our goods, services and personnel, which in turn cause our capital expenditures and operating costs to rise.

We have experienced, and may continue to experience, increased inflationary pressure on our business, including increases to the costs of goods, services and personnel, which in turn cause our capital expenditures and operating costs to rise. Sustained levels of high inflation caused the U.S. Federal Reserve to increase the federal funds interest rate by 5.25% to a high of 5.375% between March 2022 and July 2023 in an effort to curb inflationary pressure on the costs of goods and services. While inflationary pressures in the United States' economy have begun to subside, inflation is still holding above the U.S. Federal Reserve's target level. Further, despite the U.S. Federal Reserve decreasing the federal funds interest rate to 3.625% between September 2024 and December 2025, we continue to be impacted by the elevated federal funds interest rate, which could additionally have the effects of raising the cost of capital and depressing economic growth, either of which (or the combination thereof) could hurt the financial and operating results of our business.

We could experience periods of higher costs as activity levels fluctuate or if commodity prices rise. These increases could reduce our profitability, cash flow, and ability to complete development activities as planned.

An increase in commodity prices or other factors could result in increased development activity and investment in our areas of operations, which may increase competition for and cost of equipment, labor and supplies. Shortages of, or increasing costs for, experienced drilling crews and equipment, labor or supplies could restrict our operating partners' ability to conduct desired or expected operations. In addition, capital and operating costs in the oil and natural gas industry have generally risen during periods of increasing commodity prices as producers seek to increase production in order to capitalize on higher commodity prices. In situations where cost inflation exceeds commodity price inflation, our profitability and cash flow, and our operators' ability to complete development activities as scheduled and on budget, may be negatively impacted. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash flows.

We depend on computer and telecommunications systems, and failures in our systems or cybersecurity attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed or may develop proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible that we, or these third parties, could incur interruptions from cybersecurity attacks, computer viruses or malware, or that third-party service providers could cause a breach of our data. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to, or breaches of, our information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. Furthermore, various third-party resources that we rely on, directly or indirectly, in the operation of our business (such as pipelines and other infrastructure) could suffer interruptions or breaches from cyber-attacks or similar events that are entirely outside our control, and any such events could significantly disrupt our business operations and/or have a material adverse effect on our results of operations. To our knowledge we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer material losses in the future.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 26% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2025. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our acquisition strategy will subject us to certain risks associated with the inherent uncertainty in evaluating properties for which we have limited information.

We intend to continue to expand our operations in part through acquisitions. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not economically feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections are often not performed on properties being acquired, and environmental matters, such as subsurface contamination, are not necessarily observable even when an inspection is undertaken. Any acquisition involves other potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs;
- a decrease in our liquidity by using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

- the ultimate value of any contingent consideration agreed to be paid in an acquisition;
- dilution to stockholders if we use equity as consideration for, or to finance, acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and
- an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes, or other litigation encountered in connection with an acquisition.

We may be unable to successfully integrate recently acquired assets or any assets we may acquire in the future into our business or achieve the anticipated benefits of such acquisitions.

Our ability to achieve the anticipated benefits of our recent or any future acquisitions will depend in part upon whether we can integrate the acquired assets into our existing business in an efficient and effective manner. We may not be able to accomplish this integration process successfully. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- availability and cost of transportation of production to markets;
- availability and cost of drilling equipment and of skilled personnel;
- development and operating costs including access to water and potential environmental and other liabilities; and
- regulatory, permitting and similar matters.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we have performed reviews of the subject properties that we believe to be generally consistent with industry practices. The reviews are based on our analysis of historical production data, assumptions regarding capital expenditures and anticipated production declines without review by an independent petroleum engineering firm. Data used in such reviews are typically furnished by the seller or obtained from publicly available sources. Our review may not reveal all existing or potential problems or permit us to fully assess the deficiencies and potential recoverable reserves for all of the acquired properties, and the reserves and production related to the acquired properties may differ materially after such data is reviewed by an independent petroleum engineering firm or further by us. Inspections will not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or a portion of the underlying deficiencies. We are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis, and, as is the case with certain liabilities associated with the assets acquired in our recent acquisitions, we are entitled to indemnification for only certain environmental liabilities. The integration process may be subject to delays or changed circumstances, and we can give no assurance that our recently acquired assets will perform in accordance with our expectations or that our expectations with respect to integration or cost savings as a result of such acquisitions will materialize.

Our future results will suffer if we do not effectively manage our expanded operations.

As a result of our recent acquisitions, the size and geographic footprint of our business has increased. Our future success will depend, in part, upon our ability to manage this expanded business, which may pose substantial challenges for management, including challenges related to the management and monitoring of new operations and basins and associated increased costs and complexity. We may also face increased scrutiny from governmental authorities as a result of the increase in the size of our business. There can be no assurances that we will be successful or that we will realize the expected benefits currently anticipated from our recent acquisitions.

The loss of any member of our management team, upon whose knowledge, relationships with industry participants, leadership and technical expertise we rely could diminish our ability to conduct our operations and harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of those members of our management team whose knowledge, relationships with industry participants, leadership and technical expertise would be difficult to replace. In particular, our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements depends on developing and maintaining close working relationships with industry participants. In addition, our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment is dependent on our management team's knowledge and expertise in the industry. To continue to develop our business, we rely on our management team's knowledge and expertise in the industry and will use our management team's relationships with industry participants to enter into strategic relationships. The members of our management team may terminate their employment with our company at any time. If we were to lose members of our management team, we may not be able to replace the knowledge or relationships that they possess and our ability to execute our business plan could be materially harmed.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key personnel, which could have a material adverse effect on our business and results of operations.

Our ability to operate our business and implement our strategies depends on our continued ability to attract and retain highly skilled personnel with oil and natural gas industry experience and competition for these persons in the oil and gas industry is intense. Given our size and location, we may be at a disadvantage, relative to our competitors, in the competition for these personnel. We may not be able to continue to employ key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract key personnel could have a material adverse effect on our ability to effectively operate our business.

Deficiencies of title to our leased interests could significantly affect our financial condition.

We typically do not incur the expense of a title examination prior to acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights. If an examination of the title history of a property reveals that an oil or natural gas lease or other developed rights have been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value or be eliminated. In such cases, the amount paid for such oil or natural gas lease or leases or other developed rights may be lost. It is generally our practice not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we typically rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heir ship or causing an estate to be administered. Such curative work entails expense, and the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion. Furthermore, title issues may arise at a later date that were not initially detected in any title review or examination. Any one or more of the foregoing could require us to reverse revenues previously recognized and potentially negatively affect our cash flows and results of operations. Our failure to obtain perfect title to our leaseholds may adversely affect our current production and reserves and our ability in the future to increase production and reserves.

We conduct business in a highly competitive industry.

The oil and natural gas industry is highly competitive. The key areas in respect of which we face competition include: acquisition of assets offered for sale by other companies; access to capital (debt and equity) for financing and operational purposes; purchasing, leasing, hiring, chartering or other procuring of equipment by our operators that may be scarce; and employment of qualified and experienced skilled management and oil and natural gas professionals.

Competition in our markets is intense and depends, among other things, on the number of competitors in the market, their financial resources, their degree of geological, geophysical, engineering and management expertise and capabilities, their pricing policies, their ability to develop properties on time and on budget, their ability to select, acquire and develop reserves and their ability to foster and maintain relationships with the relevant authorities.

Our competitors also include those entities with greater technical, physical and financial resources. Finally, companies and certain private equity firms not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Any such companies will also increase market competition which may directly affect us. If we are unsuccessful in competing against other companies, our business, results of operations, financial condition or prospects could be materially adversely affected.

Our derivatives activities could adversely affect our cash flow, results of operations and financial condition.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the price of oil and natural gas, we enter into derivative transactions for a portion of our expected production, which may include swaps, collars, puts and other structures. In accordance with applicable accounting principles, we are required to record our derivative transactions at fair market value, and they are included on our balance sheet as assets or liabilities and in our statements of income as gain (loss) on derivatives, net. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative transactions. In addition, while intended to mitigate the effects of volatile oil and natural gas prices, our derivative transactions may reduce our performance if oil and natural gas prices were to rise over the price established by the derivative transactions.

Our actual future production for any period may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. As a result, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and, in certain circumstances, may increase the volatility of our cash flows and result in losses and reductions in liquidity. In addition, instances in which a counterparty to our derivative transactions is unable to satisfy its obligations or there is an adverse widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement may result in losses and reductions in liquidity.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with plugging, abandoning and reclaiming wells, pipelines and other facilities that we use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We accrue a liability for decommissioning costs associated with our wells, but have not established any cash reserve account for these potential costs in respect of any of our properties. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry could result in increased operating expenses and capital costs, financial risks and potential reduction in demand for oil and natural gas.

Combating the effects of climate change continues to attract considerable attention in the United States and internationally, including from regulators, legislators, companies in a variety of industries, financial market participants and other stakeholders. This focus, together with changes in consumer and industrial/commercial behavior, preferences and attitudes with respect to the generation and consumption of energy, petroleum products and the use of products manufactured with, or powered by, petroleum products, may in the long-term result in (i) the enactment of climate change-related regulations, policies and initiatives (at the government, regulator, corporate and/or investor community levels), including alternative energy requirements, new fuel consumption standards, energy conservation, enhanced disclosure obligations and emissions reductions measures and responsible energy development, (ii) technological advances with respect to the generation, transmission, storage and consumption of energy (*e.g.*, wind, solar and hydrogen power, smart grid technology and battery technology, increasing efficiency) and (iii) increased availability of, and increased consumer and industrial/commercial demand for, alternative energy sources and products manufactured with, or powered by, alternative energy sources (*e.g.*, electric vehicles and renewable residential and commercial power supplies).

Climate change legislation and regulatory initiatives may arise from a variety of sources, including international, national, regional and state levels of government and associated administrative bodies, seeking to monitor, restrict or regulate existing emissions of GHGs, such as carbon dioxide and methane, as well as to restrict or eliminate future emissions. Accordingly, our business and operations, and those of our operating partners, are subject to executive, regulatory, political and financial risks associated with oil and natural gas services and products and the emission of GHGs. Any legislation or regulatory programs related to climate change could increase our costs and require substantial capital, compliance, operating and maintenance costs, and reduce demand for oil and natural gas products and services. See further discussion in the risk factor further below entitled "*The adoption of climate change legislation or regulations restricting or relating to emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas we produce.*"

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices, and the increased competitiveness of alternative energy sources could reduce demand for oil and natural gas. Additionally, the increased competitiveness of alternative energy sources (such as electric vehicles, wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues. Such developments may also adversely impact, among other things, the availability to operators at our properties of necessary third-party services and facilities that they rely on or impact the market prices of or our operating partners' access to raw materials, which may adversely affect our ability to successfully carry out our business strategy.

Additionally, certain segments of the investor community have expressed negative sentiment towards investing in the oil and natural gas industry. Climate change-related developments in particular may result in negative perceptions of the traditional oil and gas industry and, in turn, reputational risks associated with exploration and production activities. There have been efforts in recent years, for example, to influence the investment community, including investment advisors, insurance companies and certain sovereign wealth, pension and endowment funds and other groups, by promoting divestment of fossil fuel equities and pressuring lenders to limit funding and insurance underwriters to limit coverages to companies engaged in the extraction of fossil fuel reserves. Financial institutions may elect in the future to shift some or all of their investment into non-fossil fuel related sectors. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. With the continued volatility in oil and natural gas prices, and persistently high borrowing costs, certain investors have emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially shale producers. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Increasing attention to climate change may also result in additional governmental investigations, private litigation against us, operational delays or restrictions, increased operating costs, and additional regulatory burdens. For example, claims have been made against certain companies in the energy industry alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law, or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception in relation to climate change or other environmental matters could cause the permits our operating partners need to conduct their operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Ultimately, any legislation, regulatory programs, technological advances or social pressures related to climate change could increase our operating and compliance costs, reduce demand for oil and natural gas services and products, together with a change in investor sentiment, may have a material adverse effect on our business, financial condition, results of operations and cash flows. Furthermore, if we are unable to achieve the desired level of capital efficiency or free cash flow within the timeframe expected by the market, our stock price may be adversely affected.

Increased scrutiny and changing stakeholder expectations with respect to environmental, social and governance ("ESG") matters may impact our business and expose us to additional risks.

Companies across all industries continue to face increasing scrutiny from stakeholders related to their ESG and sustainability practices. Failure or a perception (whether or not valid) of failure to implement our ESG strategy or achieve sustainability goals we may set could damage our reputation, causing our investors or other stakeholders to lose confidence in our company, and negatively impact our operations. There can be no assurance that we will be able to accomplish any announced goals, initiatives, commitments or objectives related to our ESG strategy, as statements regarding the same reflect our current plans and aspirations and are not guarantees that we will be able to achieve them within the timelines we announce, or at all. We may determine in our discretion that it is not feasible or practical to implement or complete certain of our ESG goals, initiatives, policies or procedures based on cost, timing or other considerations. Our continuing efforts to research, establish, accomplish and accurately report on the implementation of our ESG strategy, including any ESG goals, may also create additional operational risks and expenses and expose us to reputational, legal and other risks. Moreover, while we create and publish voluntary disclosures regarding ESG matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. Relatedly, there is increasing focus by regulators, customers and other stakeholders on greenwashing issues and environmental marketing and sustainability-related claims. There can be no assurance that we will not be subject to greenwashing allegations or claims associated with the veracity of our environmental and sustainability-related claims, including any claims related to our emissions reductions initiatives or the sustainability practices of our operators, among other things, which could expose us to liabilities or require us to incur additional costs to adequately prepare disclosures or improve internal controls. There is also increasing focus on ESG and sustainability disclosure and regulation across various jurisdictions and exposure to any new regulatory and legal requirements may lead to increased operational costs and compliance burden for us. The occurrence of any of the foregoing could have a material adverse effect on our business and financial condition.

Further, our business and growth opportunities require us to have strong relationships with various key stakeholders, including our stockholders, lenders, employees, suppliers, customers, local communities and others. We may face pressures from stakeholders to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability, or with respect to other ESG matters, while at the same time remaining a successfully operating public company. At the same time, recent “anti-ESG” political developments could subject the Company to increased risk of criticism or litigation risks from certain “anti-ESG” parties including various government agencies. Such sentiment may focus on the Company’s environmental or social initiatives, which anti-ESG proponents may assert as unlawful, political or polarizing in nature. If we do not successfully manage expectations across these varied stakeholder interests, it could erode our stakeholder trust and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions and thus unfavorable ESG ratings could have a negative impact on our stock price and our access to and costs of capital.

Risks Related to Our Financing and Indebtedness

Any significant reduction in our borrowing base under our Revolving Credit Facility will negatively impact our liquidity and could adversely affect our business and financial results.

Availability under our Revolving Credit Facility is subject to a borrowing base, with scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Revolving Credit Facility. The lenders under the Revolving Credit Facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Revolving Credit Facility. Reductions in estimates of our producing oil, NGL and natural gas reserves could result in a reduction of our borrowing base thereunder. The same could also arise from other factors, including but not limited to lower commodity prices or production; inability to drill or unfavorable drilling results; changes in crude oil, NGL and natural gas reserve engineering; increased operating and/or capital costs; or other factors affecting our lenders’ ability or willingness to lend (including factors that may be unrelated to our company). Any significant reduction in our borrowing base could result in a default under current and/or future debt instruments, negatively impact our liquidity and our ability to fund our operations and, as a result, could have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our Revolving Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. If we do not have sufficient funds and we are otherwise unable to arrange new financing, we may have to sell significant assets or take other actions to address. Any such sale or other actions could have a material adverse effect on our business and financial results.

Our Revolving Credit Facility and other agreements governing indebtedness contain operating and financial restrictions that may restrict our business and financing activities.

Our Revolving Credit Facility, and the Senior Notes Indentures (as defined herein), and any future indebtedness we incur may contain a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things: declare or pay any dividend or make any other distributions on, purchase or redeem our equity interests or purchase or redeem certain debt; make loans or certain investments; make certain acquisitions and investments; incur or guarantee additional indebtedness or issue certain types of equity securities; incur liens; transfer or sell assets; create subsidiaries; consolidate, merge or transfer all or substantially all of our assets; and engage in transactions with our affiliates. In addition, the Revolving Credit Facility requires us to maintain compliance with certain financial covenants and other covenants, including, among others, (i) maintaining a minimum current ratio (defined as consolidated current assets including unused amounts of the total commitments, but excluding non-cash assets under FASB Accounting Standards Codification ("ASC") Topic 815, Derivatives and Hedging ("ASC 815"), divided by consolidated current liabilities excluding current non-cash obligations under ASC 815, current maturities under the Revolving Credit Facility and current maturities of any long-term debt (the "Current Ratio")) of no less than 1.00 to 1.00 and (ii) maintaining a maximum net leverage ratio (defined as, as of the date of determination, the ratio of total net debt to EBITDAX (as defined in the Revolving Credit Facility) measured on a rolling four quarter basis (the "Net Leverage Ratio")) of 3.50 to 1.00. EBITDAX, as defined in the Revolving Credit Facility, excludes, among other things, the effects of interest expense, depreciation, depletion and amortization, income tax, certain non-cash gains and impairments, and certain restructuring costs. As a result of the financial covenants and other covenants, we could be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our Revolving Credit Facility or any other indebtedness could result in an event of default under our Revolving Credit Facility or our other indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our Revolving Credit Facility occurs and remains uncured, the lenders thereunder would not be required to lend any additional amounts to us; could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable; may have the ability to require us to apply all of our available cash to repay these borrowings; and may prevent us from making debt service payments under our other agreements.

An event of default or an acceleration under our Revolving Credit Facility could result in an event of default and an acceleration under other existing or future indebtedness. Conversely, an event of default or an acceleration under any other existing or future indebtedness could result in an event of default and an acceleration under our Revolving Credit Facility. In addition, our obligations under the Revolving Credit Facility are collateralized by perfected liens and security interests on substantially all of our assets and if we default thereunder the lenders could seek to foreclose on our assets.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as refinancing or restructuring our debt; selling assets; reducing or delaying capital investments; or seeking to raise additional capital. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

Our ability to pay dividends to our stockholders is restricted by applicable laws and regulations and requirements under certain of our debt agreements, including our Revolving Credit Facility and the Senior Notes Indentures.

Holders of our common stock are only entitled to receive such cash dividends as our board of directors, in its sole discretion, may declare out of funds legally available for such payments. We have paid quarterly dividends since 2021. We cannot assure you, however, that we will pay dividends in the future in the current amounts or at all. Our board of directors may change the timing and amount of any future dividend payments or eliminate the payment of future dividends to our common stockholders at its discretion, without notice to our stockholders. Any future determination relating to our dividend policy will be dependent on a variety of factors, including our financial condition, earnings, legal requirements, our general liquidity needs, and other factors that our board of directors deems relevant. Our ability to declare and pay dividends to our stockholders is subject to certain laws, regulations, and policies, including minimum capital requirements and, as a Delaware corporation, we are subject to certain restrictions on dividends under the DGCL. Under the DGCL, our board of directors may not authorize payment of a dividend unless it is either paid out of our surplus, as calculated in accordance with the DGCL, or if we do not have a surplus, it is paid out of our net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. Finally, our ability to pay dividends to our stockholders may be limited by covenants in any debt agreements that we are currently a party to, including our Revolving Credit Facility and the Senior Notes Indentures, or may enter into in the future. As a consequence of these various limitations and restrictions, we may not be able to make, or may have to reduce or eliminate at any time, the payment of dividends on our common stock. If as a result, we are unable to pay dividends, investors may be forced to rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Any change in the level of our dividends or the suspension of the payment thereof could have a material adverse effect on the market price of our common stock.

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

Borrowings under our Revolving Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital and our liquidity.

Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under review for a downgrade, could impact our ability to access debt markets in the future to refinance existing debt or obtain additional funds and affect the market value of the Senior Notes (as defined herein). Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency of the likelihood we will be able to repay our debt at the time the rating is issued. An explanation of the significance of each rating may be obtained from the applicable rating agency. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant.

We may be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future, subject to certain limitations, including under our Revolving Credit Facility, the Senior Notes Indentures and under any future debt agreements. If new debt is added to our current debt levels, the related risks that we now face could increase. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

Our business plan requires significant capital expenditures, which we may be unable to obtain on favorable terms or at all.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, borrowings under our credit facilities, debt issuances, and equity issuances. Cash reserves, cash from operations and borrowings under our Revolving Credit Facility may not be sufficient to fund our continuing operations and business plan and goals. We may require additional capital and we may be unable to obtain such capital if and when required. If our access to capital were limited due to numerous factors, which could include a decrease in operating cash flow due to lower oil and natural gas prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to develop our properties, replace our reserves and pursue our business plan and goals. We may not be able to incur additional debt under our Revolving Credit Facility, issue debt or equity, engage in asset sales or access other methods of financing on acceptable terms or at all. If the amount of capital we are able to raise from financing activities, together with our cash from operations, is not sufficient to satisfy our capital requirements, we may not be able to implement our business plan and may be required to scale back our operations, sell assets at unattractive prices or obtain financing on unattractive terms, any of which could adversely affect our business, results of operations and financial condition.

The capped call transactions may affect the value of the Convertible Notes and our common stock.

In connection with the pricing of our 3.625% convertible senior notes due 2029 (the "Convertible Notes") in October 2022 and our offering of Additional Convertible Notes (as defined herein) in June 2025, we entered into privately negotiated capped call transactions relating to such notes with the option counterparties. The capped call transactions relating to the Convertible Notes cover, subject to customary adjustments, the number of shares of our common stock that initially underlie such notes. The capped call transactions are expected generally to reduce the potential dilution to our common stock upon any conversion of the Convertible Notes and/or offset any potential cash payments we are required to make in excess of the principal amount of converted notes, as the case may be, with such reduction and/or offset subject to a cap.

The option counterparties and/or their respective affiliates may modify their hedge positions by entering into or unwinding various derivatives with respect to our common stock and/or purchasing or selling our common stock or other securities of ours in secondary market transactions prior to the maturity of the Convertible Notes (and are likely to do so during any observation period related to a conversion of such notes). This activity could also cause or avoid an increase or a decrease in the market price of our common stock or the Convertible Notes, which could affect a holder's ability to convert their Convertible Notes and, to the extent the activity occurs following conversion or during any observation period related to a conversion of the Convertible Notes, it could affect the amount and value of the consideration that a holder will receive upon conversion of such notes.

The potential effect, if any, of these transactions and activities on the market price of our common stock or the Convertible Notes will depend in part on market conditions and cannot be ascertained at this time. Any of these activities could adversely affect the value of our common stock and the value of the Convertible Notes (and as a result, the amount and value of the consideration that a holder would receive upon the conversion of the Convertible Notes) and, under certain circumstances, a holder's ability to convert their Convertible Notes.

We are subject to counterparty risk with respect to the capped call transactions, and the capped call transactions may not operate as planned.

The option counterparties to the capped call transactions are financial institutions, and we are subject to the risk that one or more of the option counterparties may default or otherwise fail to perform under, or may exercise certain rights to terminate, the capped call transactions. Our exposure to the credit risk of the option counterparties is not secured by any collateral. Global economic conditions have from time to time resulted in the failure or financial difficulties of many financial institutions. If an option counterparty to one or more capped call transactions becomes subject to insolvency proceedings, we will become an unsecured creditor in those proceedings with a claim equal to the value of our capped call transaction with that option counterparty. The value of our capped call transactions will depend on many factors, but, generally, will increase with increases in the market price and/or the volatility of our common stock. In addition, upon a default or other failure to perform under, or a termination of, a capped call transaction by an option counterparty, we may suffer adverse tax consequences and more dilution than we currently anticipate with respect to our common stock. We can provide no assurances as to the financial stability or viability of any option counterparty.

In addition, the capped call transactions are complex, and they may not operate as planned. For example, the terms of the capped call transactions may be subject to adjustment if certain corporate or other transactions occur.

The Convertible Notes may have a material effect on our reported financial results.

We will be required to record a greater amount of non-cash interest expense in current and future periods as a result of the amortization of the debt issuance costs for the Convertible Notes. We will report lower net income (or greater net loss) in our financial results because the application of generally accepted accounting principles in the United States ("GAAP") requires interest to include both the current period's amortization of the debt issuance costs and the instrument's coupon interest, which could adversely affect our reported or future financial results, the market price of our common stock and the trading price of the Convertible Notes.

In addition, because we have the ability to settle the Convertible Notes, upon conversion, by paying or delivering cash equal to the principal amount of the obligation and common stock for amounts over the principal amount, the shares issuable upon conversion of the Convertible Notes are accounted for using the if-converted method and, as such, are not included in the calculation of diluted earnings per share except to the extent that the conversion value of the Convertible Notes exceeds their principal amount. Further, under the if-converted method, the dilutive shares are computed assuming the maximum dilutive impact. We cannot be sure that we will be able to continue to demonstrate the ability to settle the Convertible Notes in cash or that the accounting standards will continue to permit the use of the if-converted method. If we are unable to use the if-converted method in accounting for the shares issuable upon conversion of the Convertible Notes, our diluted earnings per share could be adversely affected.

The conditional conversion feature of the Convertible Notes, if triggered, could adversely affect our financial position and liquidity.

In the event the conditional conversion feature of the Convertible Notes is triggered, holders of Convertible Notes will be entitled to convert such notes at any time during specified periods at their option. If one or more holders elect to convert their Convertible Notes, we would be required to settle any converted principal amount of such Convertible Notes through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their Convertible Notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of the Convertible Notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

Provisions in the indenture governing the Convertible Notes could delay or prevent an otherwise beneficial takeover of us.

Certain provisions in the indenture governing the Convertible Notes could make a third-party attempt to acquire us more difficult or expensive. For example, if a takeover constitutes a fundamental change, then noteholders will have the right to require us to repurchase their notes for cash. In addition, if a takeover constitutes a make-whole fundamental change, then we may be required to temporarily increase the conversion rate. In either case, and in other cases, our obligations under the notes and the indenture could increase the cost of acquiring us or otherwise discourage a third party from acquiring us, including in a transaction that noteholders or holders of our common stock may view as favorable.

Risks Related to Legal and Regulatory Matters

The executive branch and/or Congress could enact additional rules and regulations that restrict our ability to acquire federal leases in the future and/or impose more onerous permitting and other costly environmental, health and safety requirements.

We are affected by the adoption of laws, regulations and policy directives that, for economic, environmental protection or other policy reasons, could curtail exploration and development drilling for oil and gas. For example, in January 2021, the Biden Administration directed the U.S. Department of the Interior ("DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. Litigation over the leasing pause remains ongoing. Additionally, in April 2024, DOI finalized a rule to revise outdated fiscal terms of the onshore federal oil and gas leasing program, including for bonding requirements, royalty rates and minimum bids. However, in January 2025, President Trump issued executive orders (i) reversing the Biden Administration's leasing pause and executive orders withdrawing certain lands and waters from federal oil and gas leasing, (ii) directing the heads of all federal agencies to facilitate the leasing, siting, and generation of domestic energy resources, including on federal lands and waters, and (iii) directing the heads of federal agencies to begin the processes to suspend, revise, or rescind all agency actions that impose an undue burden on the identification, development, or use of domestic energy resources. As a result, future implementation and enforcement of these rules and policies remains uncertain.

In addition, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the U.S. For example, in June 2016, the EPA published NSPS, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the natural gas and oil sector to reduce methane gas and VOC emissions. In December 2023, the EPA finalized more stringent methane rules, later published in March 2024, for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc. Notably, the EPA updated the applicability date for certain requirements to a construction date of December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance deadlines under state plans. Under the final rules, which went into effect in May 2024, states have until March 2026 to prepare and submit their plans to impose methane emission controls on existing sources and those existing sources themselves have until 2029 to comply. The presumptive standards established under the final rule are generally the same for both new and existing sources. The requirements include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems and zero-emission requirements for certain devices. The rule also establishes a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. However, in March 2025, the EPA announced its intention to reconsider the March 2024 rule, including Subparts OOOOb and OOOOc, with a final rule expected in or around July 2026. A subsequent rule finalized on November 26, 2025 gives states, along with federal tribes that wish to regulate existing sources, until January 2027 to develop and submit their plans for reducing methane emissions from existing sources. Fines and penalties for violation of these rules can be substantial. However, the final rule and its requirements are currently subject to legal challenges but remain in effect. Further, in September 2021, the Biden Administration publicly announced the Global Methane Pledge, an international pact that aims to reduce global methane emissions by at least 30% below 2020 levels by 2030. However, in January 2025, President Trump issued executive orders directing (i) the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources and (ii) the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change, including the Global Methane Pledge. Consequently, future implementation and enforcement of the final methane rule remains uncertain at this time. To the extent that future legislative or regulatory changes impose more restrictive requirements pertaining to permitting, GHG emissions, financial assurance and bonding for decommissioning liabilities, or carbon taxes, such actions could adversely affect our financial condition and results of operations by restricting the lands available for development and/or access to permits required for such development, or by imposing additional and costly environmental, health and safety requirements. While the Supreme Court's decision in *Loper Bright Enterprises v. Raimondo* to overrule *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.* and end the concept of general deference to regulatory agency interpretations of laws introduces new complexity for federal agencies and administration of climate change policy and regulatory programs, many of these initiatives are expected to continue. Consequently, legislation and regulatory programs to address climate change or reduce emissions of GHGs could have a material adverse effect on our business, financial condition or results of operations.

Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

We have net operating loss ("NOL") carryforwards that we may use to offset against taxable income for U.S. federal income tax purposes. As of December 31, 2025, we had an estimated NOL carryforward of approximately $532.8 million for U.S. federal income tax purposes. In general, under Section 382 of the Internal Revenue Code of 1986, as amended (the "IRC"), a corporation that undergoes an "ownership change" can be subject to limitations on the use of its NOLs to offset future taxable income. We underwent an "ownership change" during 2018 and, as a result, the use of $121.7 million of our remaining NOL carryforwards is subject to limitations under Section 382, which are generally determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382 of the IRC. See Note 10 to our financial statements. Future changes in our stock ownership, some of which are outside of our control, could result in an additional ownership change under Section 382 of the IRC.

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.

From time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but have not been limited to, (i) the repeal of the percentage depletion allowance for natural gas and oil properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in recent federal tax legislation, Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. Moreover, other more general features of any additional tax reform legislation, including changes to cost recovery rules, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted in future legislation and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development or increase costs, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The enactment of new or increased severance taxes and impact fees on natural gas production could negatively impact our assets in the Marcellus Shale formation.

The tax laws, rules and regulations that affect the operation of our assets in the Marcellus Shale formation are subject to change. For example, Pennsylvania's governor has in past legislative sessions proposed legislation to impose a state severance tax on the extraction of natural resources, including natural gas produced from the Marcellus Shale formation, either in replacement of or in addition to the existing state impact fee. Pennsylvania's legislature has not thus far advanced any of the governor's severance tax proposals; however, severance tax legislation may continue to be proposed in future legislative sessions. Any such tax increase or change could adversely impact our earnings, cash flows and financial position as it relates to these assets.

Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.

We are subject to taxes by U.S. federal, state and local tax authorities. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including changes in the valuation of our deferred tax assets and liabilities, expected timing and amount of the release of any tax valuation allowances, or changes in tax laws, regulations or interpretations thereof. In addition, we may be subject to audits of our income, sales and other transaction taxes by U.S. federal, state and local taxing authorities. Outcomes from these audits could have an adverse effect on our financial condition and results of operations.

Changes to applicable tax laws and regulations may result in our incurring increased administrative and compliance costs and additional income tax liabilities, which could have an adverse effect on our business, results of operations and financial condition.

We are subject to various complex and evolving U.S. federal and state income taxes. U.S. federal, state and local tax laws, policies, statutes, rules, regulations or ordinances could be implemented, interpreted, changed, modified or applied adversely to us, in each case, possibly with retroactive effect.

We are subject to a 1% U.S. federal excise tax in connection with repurchases of our shares by us.

On August 16, 2022, the IRA was signed into federal law. The IRA provides for, among other things, a new U.S. federal 1% excise tax on certain repurchases (including redemptions) of shares by publicly traded domestic (i.e., U.S.) corporations and certain domestic subsidiaries of publicly traded foreign corporations occurring after December 31, 2022. The excise tax is imposed on the repurchasing corporation itself, not its shareholders from which shares are repurchased. The amount of the excise tax is generally 1% of the fair market value of the shares repurchased at the time of the repurchase. However, for purposes of calculating the excise tax, repurchasing corporations are permitted to net the fair market value of certain new share issuances (including those to employees) against the fair market value of shares repurchases during the same taxable year. In addition, certain exceptions apply to the excise tax.

Whether and to what extent we are subject to the excise tax in connection with repurchases of our shares depends on a number of factors, including the fair market value of the repurchase and the nature and amount of any equity issuances within the same taxable year of the repurchase. Any excise tax will cause a reduction in our cash available on hand, which could have a negative impact on our business and operations.

Our business involves the selling and shipping by rail of crude oil, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.

A portion of our crude oil production is transported to market centers by rail. Derailments in North America of trains transporting crude oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable liquids. Any changes to existing laws and regulations, or promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, any derailment of crude oil involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities.

Our derivatives activities expose us to potential regulatory risks.

The Federal Trade Commission, FERC, and the Commodities Futures Trading Commission ("CFTC") have statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to derivative activities that we undertake with respect to oil, natural gas, NGLs, or other energy commodities, we are required to observe the market-related regulations enforced by these agencies. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

Legislative and regulatory developments could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

On January 14, 2021, the CFTC published a final rule imposing position limits for certain futures and options contracts in various commodities (including oil and gas) and for swaps that are their economic equivalents, though certain types of derivative transactions are exempt from these limits, provided that such derivative transactions satisfy the CFTC's requirements for certain enumerated "bona fide" hedging transactions and positions. The CFTC has also adopted final rules regarding aggregation of positions, under which a party that controls the trading of, or owns ten percent or more of the equity interests in, another party will have to aggregate the positions of the controlled or owned party with its own positions for purposes of determining compliance with position limits unless an exemption applies. These rules may affect both the size of the positions that we may hold and the ability or willingness of counterparties to trade with us, potentially increasing the costs of, and/or materially reducing our access to, derivative transactions, which could adversely affect revenues and cash flow.

We maintain an active hedging program related to commodity price risks. If we reduce our use of derivatives as a result of legislation and regulations or any resulting changes in the derivatives markets, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures or to make payments on our debt obligations. In addition, if a consequence of legislation and regulations is to lower commodity prices, our revenues could be adversely affected. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Our business is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operational interests, as operated by our third-party operating partners, are regulated extensively at the federal, state, tribal and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, our company (either directly or indirectly through our operating partners) could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our business and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we do business includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our business and limit the quantity of natural gas we may produce and sell. A major risk inherent in the drilling plans in which we participate is the need for our operators to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on the development of our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff.

Failure to comply with federal, state and local environmental laws and regulations could result in substantial penalties and adversely affect our business.

All phases of the oil and natural gas business can present environmental risks and hazards and are subject to a variety of federal, state and municipal laws and regulations. Environmental laws and regulations, among other things, restrict and prohibit spills, releases or emissions of various substances produced in association with oil and natural gas operations, and require that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. There is risk of incurring significant environmental costs and liabilities as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our business, and historical operations and waste disposal practices. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the imposition of injunctive relief.

Environmental legislation may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge, regardless of whether we were responsible for the release or contamination and regardless of whether our operating partners met previous standards in the industry at the time they were conducted. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of operations on our properties. The application of new or more stringent environmental laws and regulations to our business may cause us to curtail production or increase the costs of our production, development or exploration activities.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is used extensively by our third-party operating partners. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Any federal or state legislative or regulatory changes with respect to hydraulic fracturing could cause us to incur substantial compliance costs or result in operational delays, and the consequences of any failure to comply by us or our third-party operating partners could have a material adverse effect on our financial condition and results of operations. Hydraulic fracturing typically is regulated by state gas and oil commissions or similar state agencies, but several federal agencies have conducted studies or asserted regulatory authority over certain aspects of the process. For example, in late 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances. The EPA's report did identify future efforts that could be taken to further understand the potential impacts of hydraulic fracturing to drinking water resources, including groundwater and surface water monitoring in areas with hydraulically fractured natural gas and oil producing wells. To date, the EPA has taken no further action in response to the 2016 report. Additionally, the EPA has asserted regulatory authority pursuant to the Safe Drinking Water Act UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing.

In addition, in response to concerns relating to recent seismic events near underground disposal wells used for the disposal by injection of flowback and produced water or certain other oilfield fluids resulting from oil and natural gas activities (so-called "induced seismicity"), regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. States may, from time to time, develop and implement plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. These developments could result in additional regulation and restrictions on the use of injection wells by our operators to dispose of flowback and produced water and certain other oilfield fluids. Increased regulation and attention given to induced seismicity also could lead to greater opposition to, and litigation concerning, oil and natural gas activities utilizing injection wells for waste disposal. Until such pending or threatened legislation or regulations are finalized and implemented, it is not possible to estimate their impact on our business.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

The adoption of climate change legislation or regulations restricting or relating to emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Restrictions on GHG emissions that may be imposed, or the adoption and implementation of regulations by governmental entities in the U.S. or other countries that require reporting of GHG emissions or other climate-related information or otherwise seek to limit GHG emissions (including carbon pricing schemes) from our operating partners, could adversely affect our business and the oil and gas industry, including by restricting our ability to execute on our business strategy, requiring additional capital, compliance, operating costs, increasing the cost of oil and natural gas products and services, reducing demand for oil and natural gas products and services, reducing our access to financial markets, or creating greater potential for governmental investigations or litigation. For example, adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory requirements. Such regulatory initiatives could stimulate demand for alternative forms of energy that do not rely on combustion fossil fuels. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources, our products may become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products may become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and potentially reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions or that address climate change could have an adverse effect on our business, financial condition and results of operations.

In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. See "Item 1. Business—Governmental Regulation and Environmental Matters" and "—Climate Change" for a further discussion of the laws and regulations related to GHGs and of climate change.

We have relied on an exception from the definition of "investment company" under the Investment Company Act of 1940, as amended, and the rules and regulations thereunder (the "ICA") in order to avoid being subject to the ICA.

We have relied on an exception from the definition of "investment company" under the ICA in order to avoid being subject to the ICA. To the extent the nature of our business or assets change in the future and we do not qualify for another exemption or exception under the ICA at such time, we may be required to register as an "investment company" and become subject to regulations thereunder, which would limit our business operations and require us to spend significant resources in order to comply with such regulations. To the extent a regulatory agency determines we do not qualify for exception to the ICA on which we currently rely, we may be deemed to have been in violation of the ICA, the consequences of which would be expected to be significant.

Risks Related to Our Common Stock

There may be future sales or issuances of our common stock, including issuances in connection with our incentive plans, acquisitions or otherwise, which will dilute the ownership interests of stockholders and may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes us to issue 270,000,000 shares of common stock, of which 97,265,559 shares were issued and outstanding as of December 31, 2025. Any shares of common stock that we may issue in the future, including securities that are convertible into or exchangeable for, or that represent the right to receive, common stock or substantially similar securities, may dilute the ownership interests of our stockholders. In addition, future issuances of common stock under our Amended and Restated 2018 Equity Incentive Plan or other equity incentive plans that we may adopt in the future, or in connection with an acquisition or otherwise, would also dilute the percentage ownership held by our stockholders. The market price of our common stock could decline as a result of sales or issuances of a large number of shares of our common stock or similar securities in the market or the perception that such sales or issuances could occur.

Our certificate of incorporation, bylaws, and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by our stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third-party to acquire control of us, even if the change of control would be beneficial to our stockholders, including, among others, limitations on the ability of our stockholders to call special meetings, limitations on the ability of our stockholders to act by written consent, and advance notice provisions for stockholders proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders. Delaware law generally prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who owns 15% or more of our stock cannot acquire us for a period of three years from the date such stockholder became an interested stockholder, unless various conditions are met.

The availability of shares for sale or other issuance in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue all or any part of our authorized but unissued shares of common stock, or issue shares of preferred stock, which may be convertible into shares of common stock. In the future, we may issue securities to raise cash for acquisitions, as consideration in acquisitions, to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash, our preferred stock and our common stock or just our common stock. We may also issue securities, including our preferred stock, that are convertible into, exchangeable for, or that represent the right to receive, our common stock. The occurrence of any of these events or any issuance of common stock upon conversion of our Convertible Notes may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

Investors in our common stock may be required to look solely to stock appreciation for a return on their investment in us.

Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in the instruments governing our indebtedness restrict the payment of dividends. Investors may be forced to rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Item 1B. *Unresolved Staff Comments*

None.

Item 1C. *Cybersecurity*

We have a cybersecurity risk management program to identify, monitor, and mitigate cybersecurity risks. The program consists of formal roles and responsibilities for information security and incident response, and is overseen by our IT Steering Committee, which consists of key executives and employees with guidance from our third-party cybersecurity vendor. Our enterprise risk management program considers cybersecurity risks alongside other company risks, and we consult with our cybersecurity vendor to gather information necessary to identify cybersecurity risks, evaluate their nature and severity, as well as identify mitigations and assess the impact of those mitigations on residual risk. In addition to continuous cyber monitoring, the IT Steering Committee participates in quarterly cyber updates with our cybersecurity vendor, which includes identification of new cyber risks and threats, reported vulnerabilities, trend analysis on attack vectors, and monitoring of risk mitigation activities.

The Audit Committee has ultimate oversight of cybersecurity risks and our cybersecurity risk management program. Management provides cybersecurity program briefings to the Audit Committee on at least an annual basis, and more frequently if circumstances warrant. These briefings include assessments of cyber risks, the threat landscape, updates on any incidents, and reports on our investments in cybersecurity risk mitigation and governance. Management utilizes the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) as a guideline to manage our cybersecurity risks and inform the Audit Committee on the overall progress of our information security program. To ensure continued alignment and independent verification of our NIST CSF implementation, we engage a qualified third-party cybersecurity firm to conduct periodic assessments of our program, covering all five core functions of the NIST CSF. Findings from these reviews are reported to the Audit Committee and inform our ongoing enhancements to people, process, and technology controls.

We have a formal IT Security Policy to provide appropriate governance over information security including control requirements for change management and patching, multi-factor authentication, data backup, security monitoring, mobile device management and asset management. Management performs annual testing of security controls, including penetration testing from a different cybersecurity vendor that is independent of both our Company and the cybersecurity vendor that provides guidance on our overall cybersecurity program, and results are reported to the Audit Committee. In addition, management has a formal incident response plan and our cybersecurity vendor provides 24x7 monitoring/management of our infrastructure and systems. The incident response plan addresses the lifecycle of incidents including identification, response and recovery, and the plan is tested at least annually. In addition, we carry insurance that provides protection against the potential losses arising from cybersecurity incidents.

Management maintains an inventory of third parties (e.g., vendors, consultants, etc., from whom we may face cybersecurity risk in connection with our relationship) and completes an annual third-party cyber risk assessment. In addition, employees participate in mandatory annual cybersecurity training and management conducts routine social engineering tests to monitor employees' awareness of cyber risks and to train employees on how to identify potential cybersecurity risks.

In the last two fiscal years, we have not experienced any material cybersecurity breach incidents. For additional information about our cybersecurity risks, please see "Item 1A. Risk Factors – We depend on computer and telecommunications systems, and failures in our systems or cybersecurity attacks could significantly disrupt our business operations."

Item 2. ***Properties***

Estimated Net Proved Reserves

The table below summarizes our estimated net proved reserves at December 31, 2025 based on reports prepared by the Company for the year ended December 31, 2025 and audited by Cawley, our third-party independent reserve engineers. In preparing its reports, the Company evaluated properties representing all of our proved reserves at December 31, 2025 in accordance with the rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves in the table below do not include probable or possible reserves and do not in any way include or reflect our commodity derivatives.

	December 31, 2025		December 31, 2024	
	Proved Reserves (MBoe)(1)	% of Total	Proved Reserves (MBoe)(2)	% of Total
SEC Proved Reserves:				
Developed	282,789	74 %	278,151	73 %
Undeveloped	101,279	26 %	100,333	27 %
Total Proved Properties	384,068	100 %	378,484	100 %

(1) The table above values oil and natural gas reserve quantities as of December 31, 2025, assuming constant realized prices of $59.72 per barrel of oil and $3.18 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.

(2) The table above values oil and natural gas reserve quantities as of December 31, 2024, assuming constant realized prices of $70.60 per barrel of oil and $2.02 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.

Estimated net proved reserves at December 31, 2025 were 384,068 MBoe, a 1% increase from estimated net proved reserves of 378,484 MBoe at December 31, 2024. The increase was primarily due to the impact of our 2025 acquisitions, as well as organic drilling activities in 2025. As of December 31, 2025 and 2024, we had 140.8 and 146.4 net proved undeveloped wells, respectively, included in our reserves.

The following table sets forth summary information by reserve category with respect to estimated proved reserves at December 31, 2025:

	SEC Pricing Proved Reserves[1]					
	Reserve Volumes				PV-10[3]	
Reserve Category	Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)[2]	%	Amount (In thousands)	%
PDP Properties	123,102	899,512	273,021	71 %	$ 3,498,946	77 %
PDNP Properties	3,952	34,892	9,768	3 %	140,004	3 %
PUD Properties	57,807	260,833	101,279	26 %	891,706	20 %
Total	184,861	1,195,237	384,068	100 %	$ 4,530,656	100 %

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(1) The SEC Pricing Proved Reserves table above values oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2025, based on average prices of $65.34 per barrel of oil and $3.39 per MMbtu of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per MMbtu of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. The average resulting price used as of December 31, 2025, after adjustment to reflect applicable transportation and quality differentials, was $59.72 per barrel of oil and $3.18 per Mcf of natural gas.

(2) Boe are computed based on a conversion ratio of one Boe for each barrel of oil and one Boe for every 6,000 cubic feet (i.e., 6 Mcf) of natural gas.

(3) Pre-tax PV10%, or PV-10, may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP measure. See “Reconciliation of PV-10 to Standardized Measure” below.

The table above assumes prices and costs discounted using an annual discount rate of 10% without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes. The information in the table above does not give any effect to or reflect our commodity derivatives.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure for proved reserves calculated using SEC pricing. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for reserves calculated using prices other than SEC prices. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table reconciles the pre-tax PV10% value of our SEC Pricing Proved Reserves as of December 31, 2025 to the Standardized Measure of discounted future net cash flows.

SEC Pricing Proved Reserves
(In thousands)

Standardized Measure Reconciliation	
Pre-Tax Present Value of Estimated Future Net Revenues (Pre-Tax PV10%)	$ 4,530,656
Future Income Taxes, Discounted at 10%[1]	(707,854)
Standardized Measure of Discounted Future Net Cash Flows	$ 3,822,802

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(1) The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows.

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner. As a result, estimates of proved reserves may vary depending upon the engineer estimating the reserves. Further, our actual realized price for our oil and natural gas is not likely to average the pricing parameters used to calculate our proved reserves. As such, the oil and natural gas quantities and the value of those commodities ultimately recovered from our properties will vary from reserve estimates.

Additional discussion of our proved reserves is set forth under the heading "Supplemental Oil and Gas Information - Unaudited" to our financial statements included later in this report.

Proved Undeveloped Reserves

At December 31, 2025, we had approximately 101.3 MMBoe of proved undeveloped reserves as compared to 100.3 MMBoe at December 31, 2024. A reconciliation of the change in proved undeveloped reserves during 2025 is as follows:

	MBoe
Estimated Proved Undeveloped Reserves at 12/31/2024	100,333
Converted to Proved Developed Through Drilling	(19,162)
Added from Extensions and Discoveries	27,432
Purchases of Minerals in Place	1,761
Revisions	(9,085)
Estimated Proved Undeveloped Reserves at 12/31/2025	101,279

Our future development drilling program includes the drilling of approximately 140.8 proved undeveloped net wells before the end of 2030 at an estimated cost of $1.1 billion. Our development plan for drilling proved undeveloped wells calls for the drilling of 62.9 net wells during 2026 (includes 31.5 net wells spud at December 31, 2025, but classified as proved undeveloped due to internal guidelines which require greater than 50% of total costs to be incurred to be classified as developed), 33.1 net wells during 2027, 24.4 net wells during 2028, 12.8 net wells during 2029, and 7.6 net wells during 2030 for a total of 140.8 net wells. Our proved undeveloped locations were decreased from 146.4 net wells at December 31, 2024 to 140.8 net wells at December 31, 2025 due to our 2025 development activity. We expect that our proved undeveloped reserves will continue to be converted to proved developed producing reserves as additional wells are drilled under our acreage. All locations comprising our remaining proved undeveloped reserves are forecasted to be drilled within five years from initially being recorded in accordance with our development plan.

At December 31, 2025, the PV-10 value of our proved undeveloped reserves amounted to 20% of the PV-10 value of our total proved reserves. Although our 2025 producing property additions exceeded our 5-year average development plan, there are numerous uncertainties. The development of these reserves is dependent upon a number of factors which include, but are not limited to: financial targets such as drilling within cash flow or reducing debt, drilling of obligatory wells, satisfactory rates of return on proposed drilling projects, and the levels of drilling activities by operators in areas where we hold leasehold interests. During 2025, we decreased our capital spending by 38% compared to 2024. With 77% of the PV-10 value of our total proved reserves supported by producing wells, we believe we will have sufficient cash flows and adequate liquidity to execute our development plan.

At December 31, 2025, we had spent a total of $291.0 million related to the development of proved undeveloped reserves, which resulted in the conversion of 19.2 MMBoe of proved undeveloped reserves as of December 31, 2024 to proved developed reserves as of December 31, 2025. Proved developed property additions in 2025 also included 38.3 MMBoe from the conversion of previously undeveloped locations that were not booked in our December 31, 2024 proved undeveloped reserves (the related development costs incurred at December 31, 2025 were $410.8 million). Additionally, our proved undeveloped reserves at December 31, 2025 included 37.9 MMBoe for net wells that had commenced drilling activities but remained classified as undeveloped reserves due to more than half of the capital expenditures that remain to be incurred for completion of the wells (the related development costs incurred at December 31, 2025 were $113.3 million).

In 2025, we also added 27.4 MMBoe of proved undeveloped reserves as a result of our development activity. We added an additional 1.8 MMBoe from our acquisitions. The SEC-prescribed commodity prices (after adjustment for transportation, quality and basis differentials) were $10.88 lower per barrel of oil and $1.16 higher per Mcf of natural gas at year-end 2025 as compared to year-end 2024. Additionally, we had negative revisions of 9.1 MMBoe primarily due to the significant downward trend in oil commodity prices.

Proved Reserves Sensitivity by Price Scenario

The SEC disclosure rules allow for optional reserves sensitivity analysis, such as the sensitivity that oil and natural gas reserves have to price fluctuations. We have chosen to compare our proved reserves calculated using SEC Pricing (the “2025 SEC Case”) to two alternate pricing cases. The first case scenario uses a flat pricing deck of $70.00 per Bbl for oil and $4.50 per MMbtu for natural gas (the “$70 Flat Case”). The second scenario uses a flat pricing deck of $50.00 per Bbl for oil and $3.00 per MMbtu for natural gas (the “$50 Flat Case”). The sensitivity scenarios were not audited by a third-party. In these sensitivity scenarios, all operating cost assumptions and other factors, other than the commodity price assumptions, have been held constant with the 2025 SEC Case. The change in pricing in the $50 Flat Case resulted in fewer future drilling locations that were considered economic compared to the 2025 SEC Case. This sensitivity analysis is only meant to demonstrate the impact that changing commodity prices may have on estimated proved reserves and PV-10 values. There is no assurance that any particular outcome will be realized. The table below shows our proved reserves utilizing the 2025 SEC Case compared with the $70 Flat Case and the $50 Flat Case.

	Price Cases		
	2025 SEC Case[(1)]	**$70 Flat Case[(2)]**	**$50 Flat Case[(3)]**
Net Proved Reserves (December 31, 2025)			
Oil (MBbl)			
Developed	127,054	132,340	112,308
Undeveloped	57,807	60,387	44,777
Total	184,861	192,727	157,085
Natural Gas (MMcf)			
Developed	934,404	968,756	876,193
Undeveloped	260,833	268,543	235,511
Total	1,195,237	1,237,299	1,111,704
Total Proved Reserves (MBOE)	384,068	398,944	342,369
Pre-tax PV10% (in thousands)[(4)]	$ 4,530,656	$ 5,704,714	2,788,331

(1) Represents reserves based on pricing prescribed by the SEC. The unescalated twelve month arithmetic average of the first day of the month posted prices were adjusted for transportation and quality differentials to arrive at prices of $59.72 per Bbl for oil and $3.18 per Mcf for natural gas. Production costs were held constant for the life of the wells.

(2) Prices based on $70.00 per Bbl for oil and $4.50 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $64.40 per Bbl for oil and $4.30 per Mcf for natural gas.

(3) Prices based on $50.00 per Bbl for oil and $3.00 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $44.53 per Bbl for oil and $2.77 per Mcf for natural gas.

(4) Pre-tax PV10%, or PV-10, may be considered a non-GAAP financial measure. See "Reconciliation of PV-10 to Standardized Measure" above for a reconciliation of the PV-10 of our 2025 SEC Case proved reserves to the Standardized Measure. GAAP does not prescribe a corresponding measure for PV-10 of proved reserves based on other than SEC prices. As a result, it is not practicable for us to reconcile the PV-10 of our proved reserves based on alternate pricing scenarios.

Independent Petroleum Engineers

We have utilized Cawley, an independent reserve engineering firm, as our third-party engineering firm. The selection of Cawley was approved by our Audit Committee. Cawley is a reservoir-evaluation consulting firm who evaluates oil and natural gas properties and independently certifies petroleum reserves quantities for various clients throughout the United States. Cawley has substantial experience auditing and calculating the reserves of various other companies and, as such, we believe Cawley has sufficient experience to appropriately audit our reserves. Cawley utilizes proprietary technology, systems and data to audit our reserves commensurate with this experience. Cawley is a Texas Registered Engineering Firm (F-693). Our primary contact at Cawley is Todd Brooker, President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License #83462). He is also a member of the Society of Petroleum Engineers.

In accordance with applicable requirements of the SEC, estimates of our net proved reserves and future net revenues are made using average prices at the beginning of each month in the 12-month period prior to the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation).

The reserves set forth in the Company report audited by Cawley for the properties are estimated by performance methods or analogy. In general, reserves attributable to producing wells and/or reservoirs are estimated by performance methods such as decline curve analysis which utilizes extrapolations of historical production data. Reserves attributable to non-producing and undeveloped reserves included in our report are estimated by analogy. The estimates of the reserves, future production, and income attributable to properties are prepared using the economic software package Aries for Windows, a copyrighted program of Halliburton.

To estimate economically recoverable oil and natural gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be demonstrated to be economically producible based on existing economic conditions including the prices and costs at which economic productivity from a reservoir is to be determined as of the effective date of the report. With respect to the property interests we own, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, production taxes, recompletion and development costs and product prices are based on the SEC regulations, geological maps, well logs, core analyses, and pressure measurements.

The reserve data set forth in the Company report represents only estimates, and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the actual revenues and costs could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves, included in our SEC filings, have not been filed with or included in reports to any other federal agency. See "Item 1A. Risk Factors – Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves."

Internal Controls Over Reserves Estimation Process

We employ an internal reserve engineering department which is led by our Chief Technical Officer, who is responsible for overseeing the preparation of our reserves estimates. Our executive internal reserve engineer has a B.S. in petroleum engineering from Montana Tech, has over twenty years of oil and gas experience on the reservoir side, and has experience working for large independents on projects and acquisitions. In addition, we utilize a third-party reservoir engineering firm as our independent reserves auditor for 100% of our reserves base.

Our technical team meets with our independent third-party engineering firm to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interests and net revenue interests in our reserves database against our well ownership system;
- Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;
- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineer;
- Discussion of material reserve variances among our internal reservoir engineer and our executive management; and
- Review of a preliminary copy of the reserve report by executive management.

Production, Price and Production Expense History

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown dramatically over the past few years, and the supply of oil could impact oil prices in the United States if the supply outstrips domestic demand. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,		
	2025	2024	2023
Net Production:			
Oil (MBbl)	27,611	26,511	22,013
Natural Gas (MMcf)	130,084	113,476	84,342
Total (MBoe)	49,292	45,423	36,070
Oil (MBbl) per day	76	72	60
Natural Gas (MMcf) per day	356	310	231
Total (MBoe) per day	135	124	99
Average Sales Prices:			
Oil (per Bbl) [1]	$ 59.20	$ 71.59	$ 74.78
Effect of Loss on Settled Oil Derivatives on Average Price (per Bbl)	5.15	(0.11)	(0.90)
Oil, Net of Settled Oil Derivatives (per Bbl) [1]	64.35	71.48	73.88
Natural Gas and NGLs (per Mcf) [1] [2]	2.87	2.24	2.98
Effect of Gain on Settled Natural Gas Derivatives on Average Price (per Mcf)	0.45	0.76	0.92
Natural Gas and NGLs, Net of Settled Natural Gas and NGL Derivatives (per Mcf) [1] [2]	3.32	3.00	3.90
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives [1] [2]	40.74	47.38	52.61
Effect of Gain on Settled Commodity Derivatives on Average Price (per Boe)	4.08	1.83	1.61
Realized Price on a Boe Basis Including Settled Commodity Derivatives [1] [2]	44.82	49.21	54.22
Average Costs:			
Production Expenses (per Boe)	$ 9.61	$ 9.46	$ 9.62

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[1] Excludes the impact of certain non-cash adjustments to revenues
[2] Excludes the impact of a legal settlement (See Note 2 to our financial statements)

The following table sets forth our production results for the years ended December 31, 2025, 2024 and 2023 in total and for each of our basins of operations.

	Year Ended December 31,		
	2025	**2024**	**2023**
Net Production:			
Oil (MBbl)			
Williston Basin	10,607	12,241	12,747
Permian Basin	13,275	13,529	9,266
Appalachian Basin	159	56	—
Uinta Basin	3,570	685	—
Total	27,611	26,511	22,013
Natural Gas and NGLs (MMcf)			
Williston Basin	29,187	31,518	31,103
Permian Basin	48,731	44,621	28,594
Appalachian Basin	49,804	36,785	24,645
Uinta Basin	2,362	552	—
Total	130,084	113,476	84,342
Crude Oil Equivalents (MBoe)			
Williston Basin	15,471	17,494	17,931
Permian Basin	21,398	20,966	14,032
Appalachian Basin	8,460	6,186	4,108
Uinta Basin	3,963	777	—
Total	49,292	45,423	36,070

Drilling and Development Activity

The following table sets forth the number of gross and net productive and non-productive wells drilled in the years ended December 31, 2025, 2024 and 2023. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.

	December 31,					
	2025		2024		2023	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)
Development Wells:						
Oil	774	71.0	790	86.9	803	76.1
Natural Gas	90	9.7	29	3.8	16	0.5
Non-Productive	—	—	—	—	—	—
Total Development Wells	864	80.7	819	90.7	819	76.6

(1) Net Well totals in 2025, 2024 and 2023 do not include an additional 18.6, 69.4 and 80.4 net wells, respectively, from acquisitions which were already producing when acquired.

The following table summarizes our cumulative gross and net productive oil and natural gas wells by geographic area within the United States at each of December 31, 2025, 2024 and 2023. Wells are classified as oil or natural gas wells according to the predominant production stream. All of our wells in the Williston, Permian, and Uinta Basins are classified as oil wells, although they also produce natural gas and condensate. All of our wells in the Appalachian Basin are classified as natural gas wells.

	December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	8,573	682.5	8,278	664.0	7,981	643.7
Permian Basin	2,229	349.6	1,895	302.3	1,387	207.6
Appalachian Basin	518	114.2	424	104.3	397	100.3
Uinta Basin	382	49.1	271	37.4	—	—
Total	11,702	1,195.4	10,868	1,108.0	9,765	951.6

As of December 31, 2025, we had an additional 441 gross (45.6 net) wells in process, meaning wells that have been spud and are in the process of drilling, completing or waiting on completion.

Leasehold Properties

As of December 31, 2025, our principal assets included approximately 301,797 net acres located in the United States. The following table summarizes our estimated gross and net developed and undeveloped acreage by geographic area at December 31, 2025.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	875,662	169,016	43,721	8,640	919,383	177,656
Permian Basin	181,279	39,317	29,050	6,450	210,329	45,767
Appalachian Basin	131,605	27,410	97,337	34,789	228,942	62,198
Uinta Basin	225,422	14,470	56,487	1,706	281,909	16,176
Total	1,413,968	250,213	226,595	51,585	1,640,563	301,797

As of December 31, 2025, approximately 83% of our total acreage was developed. All of our proved reserves are located in the United States.

Recent Acquisitions

We generally assess acreage subject to near-term drilling activities on a lease-by-lease basis because we believe each lease’s contribution to a subject spacing unit is best assessed on that basis if development timing is sufficiently clear. Consistent with that approach, a significant portion of our acreage acquisitions involve properties that are selected by us on a lease-by-lease basis for their participation in a well expected to be spud in the near future, and the subject leases are then aggregated to complete one single closing with the transferor. As such, we generally view each acreage assignment from brokers, landmen and other parties as involving several separate acquisitions combined into one closing with the common transferor for convenience. However, in certain instances an acquisition may involve a larger number of leases presented by the transferors as a single package without negotiation on a lease-by-lease basis. In those instances, we still review each lease on a lease-by-lease basis to ensure that the package as a whole meets our acquisition criteria and drilling expectations. See Note 3 to our financial statements regarding our recent acquisition activities.

Acreage Expirations

As a non-operator, we are subject to lease expirations if an operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other “savings clause” is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to establish production from most of our acreage prior to expiration of the applicable lease terms, there can be no guarantee we can do so. The approximate expiration of our net acres which are subject to expire between 2026 and 2030 and thereafter, are set forth below:

	Acreage Subject to Expiration	
Year Ended	Gross	Net
December 31, 2026	8,651	1,899
December 31, 2027	11,161	2,727
December 31, 2028	10,308	3,239
December 31, 2029	4,158	2,676
December 31, 2030 and thereafter	12,463	8,564
Total	46,741	19,105

During 2025, we had leases expire covering approximately 4,206 net acres. The 2025 lease expirations carried a cost of $7.8 million. We believe that the expired acreage was not material to our capital deployed. As of December 31, 2025, we estimate that less than 1% of our proved undeveloped reserves were attributable to locations scheduled to be drilled after lease expiration.

Unproved Properties

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proved, all associated acreage and drilling costs are subject to depletion.

We assess all items classified as unproved property on an annual basis, or if certain circumstances exist, more frequently, for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and amortization.

We believe that the majority of our unproved costs will become subject to depletion within the next five years by proving up reserves relating to our acreage through exploration and development activities, by impairing the acreage that will expire before we can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of our reserves.

Depletion of Oil and Natural Gas Properties

Our depletion expense is driven by many factors including certain exploration costs involved in the development of producing reserves, production levels and estimates of proved reserve quantities and future developmental costs. The following table presents our depletion expenses during 2025, 2024 and 2023.

	Year Ended December 31,		
(In thousands, except per Boe data)	**2025**	**2024**	**2023**
Depletion of Oil and Natural Gas Properties	$ 810,095	$ 736,600	$ 482,306
Depletion Expense (per Boe)	16.43	16.22	13.37

Research and Development

We do not anticipate performing any significant research and development under our plan of operation.

Delivery Commitments

The Company does not have any outstanding delivery commitments as of December 31, 2025.

Item 3. *Legal Proceedings*

Our company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

Item 4. *Mine Safety Disclosures*

None.

PART II

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

Market Information

Our common stock trades on the New York Stock Exchange under the symbol "NOG." The closing price for our common stock on February 23, 2026 was $27.30 per share.

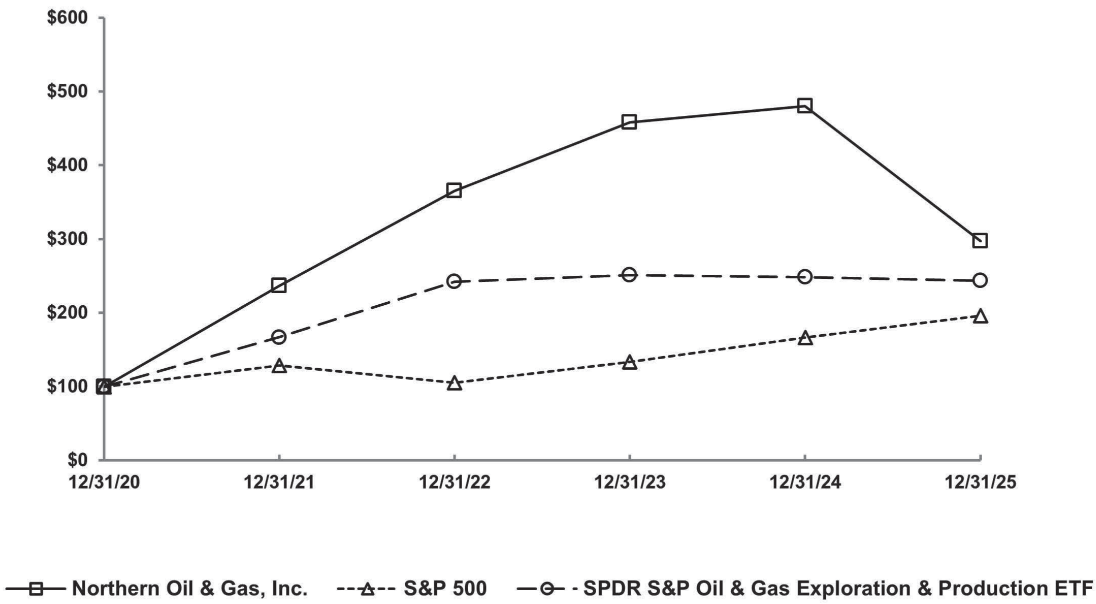
Comparison Chart

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934, as amended (the "Exchange Act") or to the liabilities of Section 18 of the Exchange Act, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares the 60-month cumulative total stockholder return on our common stock since December 31, 2020, and the cumulative total returns of the Standard & Poor's 500 Index and the SPDR S&P Oil & Gas Exploration & Production ETF for the same period. This graph tracks the performance of a $100 investment in our common stock and in each index (including reinvestment of all dividends) from December 31, 2020 to December 31, 2025.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Northern Oil & Gas, Inc., the S&P 500 Index
and the SPDR S&P Oil & Gas Exploration & Production ETF Index



*$100 invested on 12/31/20 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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The following table sets forth the total returns utilized to generate the foregoing graph.

	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
Northern Oil & Gas, Inc.	100.00	236.69	365.49	458.4	480.21	297.02
S&P 500	100.00	128.71	105.40	133.10	166.4	196.16
SPDR S&P Oil & Gas Exploration & Production ETF	100.00	166.74	242.38	251.01	248.50	243.15

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Holders

As of February 23, 2026, we had 97,294,661 shares of our common stock outstanding, held by approximately 116 stockholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

Recent Sales of Unregistered Securities

None, except to the extent previously included by the Company in a Quarterly Report on Form 10-Q or Current Report on Form 8-K.

Dividend Policy

On May 6, 2021, our board of directors declared our first cash dividend on our common stock in the amount of $0.03 per share. The dividend was paid on July 30, 2021 to stockholders of record as of the close of business on June 30, 2021. Subsequently, our board of directors declared and paid incrementally higher quarterly cash dividends, through the $0.45 per share cash dividend declared in January 2025, and paid on April 30, 2025 to stockholders of record as of the close of business on March 28, 2025. Most recently, in February 2026, our board of directors declared a cash dividend on our common stock in the amount of $0.45 per share, payable on April 30, 2026 to stockholders of record as of the close of business on March 30, 2026. We have announced our intention to set our dividend policy once per year, with the potential for interim modifications driven by material changes in realized commodity prices, significant corporate actions or other events, and currently anticipate maintaining a $0.45 per share quarterly dividend throughout 2026.

The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law, and other factors that our board of directors deems relevant at the time of such determination. Additionally, covenants contained in our Revolving Credit Facility and Senior Notes Indentures restrict the payment of cash dividends on our common stock (see Note 4 to our financial statements).

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the Company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act), of our common stock during the quarter 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 Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs(2)
October 1, 2025 to October 31, 2025	—	$ —	—	$ 160.3 million
November 1, 2025 to November 30, 2025	—	—	—	160.3 million
December 1, 2025 to December 31, 2025	356,168	21.51	326,301	153.3 million
Total	356,168	$ 21.51	326,301	$ 153.3 million

(1) Any shares purchased outside of publicly announced plans or programs represent shares surrendered in satisfaction of tax withholding obligations in connection with the vesting of restricted stock awards.

(2) On July 23, 2024, the Company's board of directors approved and promptly announced a stock repurchase program to acquire up to $150 million of the Company's outstanding common stock. On March 10, 2025, the Company's board of directors approved and promptly announced an additional $100 million authorization under this stock repurchase program. The program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

Item 6. [RESERVED]

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

The following discussion should be read in conjunction with our financial statements and accompanying notes to financial statements appearing elsewhere in this report. See Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on Form 10-K for the year ended December 31, 2024 for discussion and analysis of results of operations for the year ended December 31, 2023.

Executive Overview

Our primary strategy is to invest in non-operated minority working and mineral interests in oil and natural gas properties, with a core area of focus in the premier basins within the United States. Using this strategy, we had participated in 11,702 gross (1,195 net) producing wells as of December 31, 2025. As of December 31, 2025, we had leased approximately 301,797 net acres, of which approximately 83% were developed and all were located in the United States.

Our average daily production for full year 2025 was 135,045 Boe per day, and in the fourth quarter of 2025 was 140,064 Boe per day (approximately 53% oil). This represented significant growth from 2024, which was driven in large part by our substantial acquisition activities in 2024 and 2025, as described in Note 3 to our financial statements.

During 2025, we added 80.7 new net wells to production, plus an additional 18.6 net wells added from acquisitions which were already producing when acquired. We ended 2025 with 45.6 net wells in process.

Our financial and operating performance for the year ended December 31, 2025 included the following:

- Total production of 135,045 Boe per day, a 9% increase compared to 2024
- Cash flows from operations of $1.5 billion, a 7% increase compared to 2024
- Proved reserves of 384.1 MMBoe at year-end, a 1% increase compared to year-end 2024
- Grew our total quarterly common stock dividends by 10%, from $1.64 per share total during 2024 to $1.80 per share total during 2025
- Provided returns to shareholders totaling approximately $230.4 million, comprised of $173.4 million in common stock dividend payments and $57.0 million in repurchases of common stock
- Extended the weighted average maturity on our outstanding indebtedness to 5.4 years at year-end 2025, compared to 3.9 years at year-end 2024.

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil and natural gas production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

- *Commodity price differentials*. The price differential between our well head price for oil and the NYMEX WTI benchmark price ("Oil Price Differential") is primarily driven by the cost to transport oil via train, pipeline or truck to refineries. The price differential between our well head price for natural gas and NGLs and the NYMEX Henry Hub benchmark price ("Gas Price Differential") is primarily driven by gathering and transportation costs. As applicable, the calculations of both our Oil Price Differential and Gas Price Differential include certain immaterial non-cash revenue adjustments intended to reflect current period economic conditions.
- *Gain (loss) on commodity derivatives, net.* We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and gas. Gain (loss) on commodity derivatives, net is comprised of (i)

cash gains and losses we recognize on settled commodity derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on commodity derivative instruments outstanding at period end.

- *Production expenses.* Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, natural gas processing, salt water disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

- *Production taxes.* Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

- *Depreciation, depletion, amortization and accretion.* Depreciation, depletion, amortization and accretion includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method. Accretion expense relates to the passage of time of our asset retirement obligations.

- *General and administrative expenses.* General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, audit and other professional fees and legal compliance.

- *Interest expense.* We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our unproved cost pool. We include interest expense that is not capitalized into the unproved cost pool, the amortization of deferred financing costs (including origination and amendment fees), the amortization of bond premiums and discounts, commitment fees and annual agency fees as interest expense. Further, we record the settled amounts of our interest rate derivative instruments as interest expense.

- *Impairment expense.* Under the full cost method of accounting, the Company is required to perform a ceiling test impairment review each quarter. The test determines a limit, or ceiling, on the book value of the Company's oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. As a result of its ceiling test, the Company recorded a non-cash impairment charge of $702.7 million in the year ending December 31, 2025. The Company did not have any ceiling test impairment charges for the years ended December 31, 2024 and 2023. Average commodity prices have declined in recent months. If this downward trend continues, and/or if our proved reserves decrease significantly in future months, the present value of the Company's future net revenues could decline significantly, which could trigger the need for the Company to record an additional non-cash ceiling test impairment of its oil and gas property costs in future periods.

- *Income tax expense.* Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;

- the prices and the supply and demand for oil, natural gas and NGLs;

- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in commodity prices;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of substantially all of our acreage and wells in the Williston, Permian, Appalachian, and Uinta Basins subjects our operating results to factors specific to these operating regions. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, as well as infrastructure limitations, transportation capacity, regulatory matters and other factors that may specifically affect one or more of these operating regions.

The price at which our oil production is sold typically reflects a discount to the NYMEX WTI benchmark price. The price at which our natural gas production is sold may reflect either a discount or premium to the NYMEX Henry Hub benchmark price. Thus, our operating results are also affected by changes in the price differentials between the applicable benchmark prices and the sales prices we receive for our production.

Our average oil price differential to the NYMEX WTI benchmark price during 2025 was $5.53 per barrel, as compared to $3.88 per barrel in 2024. Our net average realized gas price during 2025 was $2.87 per Mcf, representing a 79% realization relative to the average NYMEX Henry Hub pricing, compared to a net average realized gas price of $2.24 per Mcf during 2024, which represented 93% realization relative to average NYMEX Henry Hub pricing. Fluctuations in our oil and natural gas price realizations are due to several factors, such as realized pricing by basin, gathering and transportation costs, transportation methods, takeaway capacity relative to production levels, regional storage capacity, seasonal refinery maintenance, temporarily depressing demand, and in the case of gas realizations, the price of NGLs.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in commodity prices that can substantially impact the level of drilling activity. Generally, higher commodity prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower commodity prices have generally had the opposite effect. In addition, individual components of drilling costs can vary depending on numerous factors, such as the length of the horizontal lateral, the number of fracture stimulation stages, and the type and amount of proppant used. During 2025 and 2024, the weighted average gross authorization for expenditure cost for wells we elected to participate in was $10.2 million and $9.4 million, respectively.

Market Conditions

The crude oil and natural gas industry is cyclical and commodity prices are inherently volatile. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Because our oil and gas revenues are heavily weighted toward oil, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially production from properties within the United States, the production quota set by OPEC, and the strength of the U.S. dollar can significantly impact oil prices. Factors impacting the future oil supply balance are world-wide demand for oil, as well as the growth in domestic oil production.

During 2025, a decline in oil prices occurred as a result of, among other things, (i) uncertainties regarding U.S. trade policies and tariffs driving concerns over increasing inflation, (ii) continued concerns over slowing global economic growth and resulting reductions in estimated global oil consumption, and (iii) the decision by OPEC to increase production starting in May 2025 and on multiple occasions subsequent thereto, creating additional global supply and further downward pressure on oil prices. These factors led to declining oil prices, with the NYMEX price for oil reaching levels not seen since the first quarter of 2021.

Although U.S. inflation rates were relatively stable during 2025, they remain slightly higher than historical averages. Inflationary pressures, such as trade tariffs, can lead to economic slowdown and/or lead to a recession, which in turn can cause a decrease in short-term or longer-term demand for commodities, resulting in oversupply and potential for lower commodity prices.

The foregoing destabilizing factors have caused dramatic fluctuations in global financial markets and uncertainty about world-wide oil and natural gas supply and demand, which in turn has increased the volatility of oil and natural gas prices.

Prolonged lower oil prices and inflationary costs could impact our operating partners' development schedule for the non-operated wells in which we have a working interest. Additionally, such prolonged depressed prices could result in a significant triggering event indicating the need for further impairment of our oil and natural gas assets. Any of the foregoing events or circumstances could impact our future sales volumes, operating revenues and expenses, liquidity, per unit metrics and capital expenditures.

In light of current macroeconomic uncertainty and geopolitical tensions, including developments pertaining to Russia's invasion of Ukraine, conflicts in the Middle East and Venezuela, and potential further imposition of domestic and foreign tariffs, we cannot predict any future volatility in or levels of commodity prices or demand for oil and natural gas.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the years ended December 31, 2025 and 2024.

	December 31,	
	2025	**2024**
Average NYMEX Prices[(1)]		
Oil (per Bbl)	$ 64.73	$ 75.76
Natural Gas (per MMbtu)	3.62	2.41

(1) Based on average NYMEX closing prices.

For 2025, the average NYMEX WTI pricing was $64.73 per barrel of oil, or 15% lower than the $75.76 average pricing in 2024. Our average realized oil price before reflecting settled oil derivatives was $59.20 per barrel of oil in 2025, as compared to $71.59 in 2024. Our average realized oil price after reflecting settled oil derivatives was $64.35 per barrel of oil in 2025, as compared to $71.48 in 2024, representing a 10% decline year-over-year. The lower average realized oil price in 2025 was principally due to a 15% lower average NYMEX WTI benchmark price in 2025 compared to 2024, partially offset by higher gains on settled oil derivatives.

For 2025, the average NYMEX Henry Hub pricing for natural gas was $3.62 per MMbtu, or 50% higher than the $2.41 per MMbtu price in 2024. Our average realized natural gas price before reflecting settled natural gas derivatives was $2.87 per Mcf in 2025, as compared to $2.24 per Mcf in 2024. Our average realized natural gas price after reflecting settled natural gas derivatives was $3.32 per Mcf in 2025, as compared to $3.00 per Mcf in 2024, representing an 11% increase year-over-year. The higher average realized natural gas price in 2025 is due to a higher average NYMEX Henry Hub benchmark price, partially offset by lower gains on settled natural gas derivatives in 2025 compared to 2024.

We have entered into derivatives contracts to hedge commodity price risk on a portion of our future expected oil and natural gas production. For a summary as of December 31, 2025, of our open commodity price derivative contracts for future periods, see "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" in Item 7A below. See also Note 12 to our financial statements.

Results of Operations for 2025 and 2024

The following table sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Year Ended December 31,	
	2025	2024
Net Production:		
Oil (MBbl)	27,611	26,511
Natural Gas (MMcf)	130,084	113,476
Total (MBoe)	49,292	45,423
Net Sales (in thousands):		
Oil Sales	$ 1,627,493	$ 1,897,857
Natural Gas and NGL Sales	453,795	254,222
Gain on Settled Commodity Derivatives	201,321	83,225
Gain (Loss) on Unsettled Commodity Derivatives	179,343	(21,258)
Other Revenue	13,771	11,683
Total Revenues	2,475,723	2,225,729
Average Sales Prices:		
Oil (per Bbl) (1)	$ 59.20	$ 71.59
Effect of Loss on Settled Oil Derivatives on Average Price (per Bbl)	5.15	(0.11)
Oil, Net of Settled Oil Derivatives (per Bbl) (1)	64.35	71.48
Natural Gas and NGLs (per Mcf) (1) (2)	2.87	2.24
Effect of Gain on Settled Natural Gas Derivatives on Average Price (per Mcf)	0.45	0.76
Natural Gas and NGLs, Net of Settled Natural Gas and NGL Derivatives (per Mcf) (1) (2)	3.32	3.00
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives (1) (2)	40.74	47.38
Effect of Gain on Settled Commodity Derivatives on Average Price (per Boe)	4.08	1.83
Realized Price on a Boe Basis Including Settled Commodity Derivatives (1) (2)	44.82	49.21
Operating Expenses (in thousands):		
Production Expenses	$ 473,666	$ 429,792
Production Taxes	131,334	157,091
General and Administrative Expenses	61,332	50,463
Depletion, Depreciation, Amortization and Accretion	814,859	740,901
Other Expense	12,848	9,650
Costs and Expenses (per Boe):		
Production Expenses	$ 9.61	$ 9.46
Production Taxes	2.66	3.46
General and Administrative Expenses	1.24	1.11
Depletion, Depreciation, Amortization and Accretion	16.53	16.31
Net Producing Wells at Period-End	1,195.4	1,108.0

(1) Excludes the impact of certain non-cash adjustments to revenues

(2) Excludes the impact of a legal settlement (See Note 2 to our financial statements)

Oil and Natural Gas Sales

Our revenues vary from year to year primarily as a result of changes in realized commodity prices and production volumes. In 2025, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, decreased by 3% from 2024, driven by a 14% decrease in realized prices on a per Boe basis, excluding the effect of settled commodity derivatives, partially offset by a 9% increase in production volumes. The lower average realized price in 2025 as compared to 2024 was driven primarily by lower average NYMEX oil prices in 2025 as compared to 2024, in addition to higher average oil price differentials, partially offset by higher realized gas and NGL prices in 2025 as compared to 2024. Oil price differentials during 2025 averaged $5.53 per barrel, as compared to $3.88 per barrel in 2024.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas production from existing wells. Our acquisition activities in 2025 and 2024 (see Note 3 to our financial statements) helped drive the 9% increase in production levels in 2025 as compared to 2024. In addition, the number of net wells we added to production (excluding acquisitions) increased by 11% in 2025 as compared to 2024, due to our growing organic acreage footprint and increased development on our properties.

Our production for the last two years is set forth in the following table:

	Year Ended December 31,	
	2025	**2024**
Production:		
Oil (MBbl)	27,611	26,511
Natural Gas and NGL (MMcf)	130,084	113,476
Total (MBoe)(1)	49,292	45,423
Average Daily Production:		
Oil (MBbl)	76	72
Natural Gas (MMcf)	356	310
Total (MBoe)(1)	135	124

(1) Natural gas and NGLs are converted to Boe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil and natural gas production. Our net result from commodity derivatives trade was a gain of $380.7 million in 2025, compared to a gain of $62.0 million in 2024. Net gain or loss on commodity derivatives is comprised of (i) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (ii) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

For 2025, we realized a gain on settled commodity derivatives of $201.3 million, compared to a $83.2 million gain in 2024. The increased gain on settled derivatives was primarily due to a decrease in the average NYMEX oil price in 2025 compared to 2024. The average NYMEX oil price for 2025 was $64.73 per barrel, compared to $75.76 per barrel for 2024.

During 2025, our derivative settlements included 11.9 million barrels of oil subject to swaps at an average settlement price of $73.27 per barrel, and we had an additional 9.4 million barrels of oil hedged subject to collars. Additionally, during 2025, our derivative settlements included 40.0 million MMBtu of natural gas subject to swaps at an average settlement price of $3.88 per MMBtu, and we had an additional 40.9 million MMBtu of natural gas hedged subject to collars.

During 2024, our derivative settlements included 10.5 million barrels of oil subject to swaps at an average settlement price of $74.93 per barrel, and we had an additional 8.9 million barrels of oil hedged subject to collars. Additionally, during 2024, our derivative settlements included 41.7 million MMBtu of natural gas subject to swaps at an average settlement price of $3.50 per MMBtu, and we had an additional 29.6 million MMBtu of gas hedged subject to collars. Our average realized price (including all commodity derivative cash settlements) in 2025 was $44.82 per Boe compared to $49.21 per Boe in 2024. The gain on settled commodity derivatives increased our average realized price per Boe by $4.08 and $1.83 in 2025 and 2024, respectively. The percentage of oil production hedged under our derivative contracts was 77% and 73% in 2025 and 2024, respectively.

The Company had unsettled commodity derivative gains of $179.3 million in 2025, compared to a loss of $21.3 million in 2024. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our commodity derivatives. Any gains on our unsettled commodity derivatives are expected to be offset by lower wellhead revenues in the future, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At December 31, 2025, all of our derivative contracts were recorded at their fair value, which was a net asset of $121.6 million, a change of $178.8 million from the $57.2 million net liability recorded as of December 31, 2024. The change in the fair value of our derivative contracts year-over-year was primarily due to changes in forward commodity prices relative to prices on our open commodity derivative contracts since December 31, 2024. Our open commodity derivative contracts are summarized in "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Production Expenses

Production expenses were $473.7 million in 2025, compared to $429.8 million in 2024. On a per unit basis, production expenses increased 2%, from $9.46 per Boe in 2024 to $9.61 per Boe in 2025, primarily due to higher workover costs in 2025. On an absolute dollar basis, production expenses increased 10% in 2025 compared to 2024, primarily due to a 9% increase in production volumes.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $131.3 million in 2025, compared to $157.1 million in 2024. As a percentage of oil and natural gas sales, our production taxes were 6.5% and 7.3% in 2025 and 2024, respectively. The fluctuation in our average production tax rate from year to year is primarily due to our oil and gas sales mix by basin and to certain out-of-period adjustments made to production taxes, as discussed under the heading "Out-of-Period Adjustments" in Note 2 to the financial statements.

General and Administrative Expenses

General and administrative expenses were $61.3 million for 2025, compared to $50.5 million for 2024. The increase in 2025 compared to 2024 was driven by an increase in employee compensation costs to support the Company's growth and higher acquisition-related costs, partially offset by lower professional fees.

Legal Settlement Expense

In 2025, we incurred legal expenses of approximately $33.1 million in conjunction with our $81.7 million received from an operator in North Dakota, pursuant to a legal settlement resolving our claims related to certain post-production costs previously deducted from revenues (see Note 2 to the financial statements).

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $814.9 million in 2025, compared to $740.9 million in 2024. The aggregate increase in DD&A expense for 2025 compared to 2024 was driven by a 9% increase in production levels and a 1% increase in the depletion rate per Boe. The following table summarizes DD&A expense per Boe for 2025 and 2024:

	Year Ended December 31,			
	2025	2024	Change	% Change
Depletion	$ 16.43	$ 16.22	$ 0.21	1 %
Depreciation, Amortization, and Accretion	0.10	0.09	0.01	11 %
Total DD&A expense	$ 16.53	$ 16.31	$ 0.22	1 %

Impairment Expense

In 2025, the Company recorded a non-cash impairment charge of $702.7 million as a result of its full cost ceiling test. The Company did not have any ceiling test impairment charges in 2024.

Interest Expense

Interest expense, net of capitalized interest, was $172.4 million in 2025, compared to $157.7 million in 2024. The increase in interest expense in 2025 as compared to 2024 was primarily due to higher outstanding borrowings under the Revolving Credit Facility, through the first half of 2025, to fund the Company's acquisitions activities that occurred in the latter part of 2024. See Note 3 for further information.

Loss on Debt Extinguishment

In 2025, we recorded a loss on debt extinguishment of $10.8 million, primarily due to the $10.3 million tender premium paid in conjunction with the cash tender offer to holders of our 8.125% senior notes due 2028 (the "Senior Notes due 2028") (see Note 4 to the financial statements).

Income Tax Expense

During 2025, we recorded income tax expense of $23.9 million related to federal and state income taxes, as compared to $160.5 million in 2024. The decrease in income tax expense in 2025 is primarily due to lower book income in 2025 as compared to 2024. In addition, the enactment of the One Big Beautiful Bill Act in July 2025, which reinstated the 100% additional first-year "bonus" depreciation deduction, provided favorable updates to the calculation of disallowed interest, and to the determination of whether the Company is subject to the Corporate Alternative Minimum Tax.

The effective tax rate for 2025 was 38.2% compared to an effective tax rate of 23.6% for 2024. The higher effective tax rate in 2025 was primarily due to the impact, on our deferred taxes, of the increase in our average state income tax rates, as well as adjustments for the impact of certain nondeductible items.

Liquidity and Capital Resources

Overview

Our main sources of liquidity and capital resources as of the date of this report have been internally generated cash flow from operations, proceeds from equity and debt financings, credit facility borrowings and cash settlements of commodity derivative instruments. Our primary uses of capital have been for the acquisition, development and operation of our oil and natural gas properties, cash settlements of commodity derivative instruments and for stockholder returns. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

During 2025, we repurchased and retired 1,948,996 shares of our common stock for total consideration of $57.0 million, or an average price of $29.25 per share excluding excise taxes.

We completed over $333.5 million in bolt-on acquisitions that closed during 2025 (see Note 3 to our financial statements). We financed these acquisitions with a combination of debt issuances, credit facility borrowings, and internally generated cash flow from operations.

In June 2025, we issued $200.0 million in aggregate principal amount of our Convertible Notes (the "Additional Convertible Notes") at an issue price of 105.597% of the principal amount thereof, the proceeds of which were used to reduce borrowings under our Revolving Credit Facility and for other general corporate purposes.

In October 2025, upon successfully completing the issuance of $725.0 million in aggregate principal amount of our 7.875% senior notes due 2033 (the “Senior Notes due 2033”), we repurchased approximately 97.14% of our outstanding Senior Notes due 2028, representing approximately $684.9 million in aggregate principal amount, for a total amount of $699.9 million, inclusive of tender premium and accrued interest due. Approximately $20.2 million in aggregate principal of the Senior Notes due 2028 remained outstanding at December 31, 2025.

As of December 31, 2025, we had outstanding total debt of $2,423.2 million consisting of $478.0 million of borrowings under our Revolving Credit Facility, $20.2 million aggregate principal amount of our Senior Notes due 2028 (as defined herein), $700.0 million aggregate principal amount of our Convertible Notes (as defined herein), $500.0 million aggregate principal amount of our 8.750% senior notes due 2031 (the “Senior Notes due 2031”) (as defined herein), and $725.0 million aggregate principal amount of our Senior Notes due 2033 (as defined herein).

As of December 31, 2025, we had total liquidity of $1,136.3 million, consisting of $1,122.0 million of committed borrowing availability under the Revolving Credit Facility and $14.3 million of cash on hand.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility. Oil accounted for 81% and 88% of our total oil and gas sales in 2025 and 2024, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas and NGL prices. We seek to maintain a robust hedging program to mitigate volatility in commodity prices with respect to a portion of our expected production. For the years ended 2025 and 2024, we hedged approximately 77% and 73% of our crude oil production, respectively, and approximately 62% and 63% of our natural gas production, respectively. For a summary as of December 31, 2025, of our open commodity swap contracts for future periods, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” below.

With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months and, based on current expectations, for the foreseeable future. However, we may seek additional access to capital and liquidity. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

Our recent capital commitments have been to fund acquisitions and development of oil and natural gas properties. We expect to fund our near-term capital requirements and working capital needs with cash flows from operations and available borrowing capacity under our Revolving Credit Facility. Our capital expenditures could be curtailed if our cash flows decline from expected levels. Because production from existing oil and natural gas wells declines over time, reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

Working Capital

Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, collection of receivables, expenditures related to our development and production operations and the impact of our outstanding derivative instruments. At December 31, 2025, we had a working capital surplus of $46.7 million, compared to a deficit of $43.5 million at December 31, 2024. Current assets increased by $85.3 million and current liabilities decreased by $5.0 million at December 31, 2025, as compared to December 31, 2024.

The $85.3 million increase in current assets in 2025 as compared to 2024 was primarily driven by a $120.2 million increase in derivative instruments, a $17.7 million increase in advances to operators, and a $7.2 million increase in cash and other current assets, partially offset by a $39.7 million decrease in accounts receivable and a $20.0 million decrease in income tax receivable.

The $5.0 million decrease in current liabilities in 2025 as compared to 2024 was primarily due to a $19.9 million decrease in derivative instruments and $3.0 million decrease in accrued interest, partially offset by a $17.9 million increase in accounts payable, accruals and other current liabilities.

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and by changes in working capital. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Revolving Credit Facility. We typically enter into commodity derivative transactions covering a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 36 months. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Our cash summary for the years ended December 31, 2025 and 2024 is presented below:

	Year Ended December 31,	
(In thousands)	**2025**	**2024**
Net Cash Provided by Operating Activities	$ 1,505,288	$ 1,408,663
Net Cash Used for Investing Activities	(1,252,462)	(1,674,754)
Net Cash Provided by (Used for) Financing Activities	(247,460)	266,829
Net Increase in Cash	$ 5,366	$ 738

Cash Flows from Operating Activities

Net cash provided by operating activities in 2025 was $1.5 billion, compared to $1.4 billion in 2024. Net cash provided by operating activities is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital and other items (as reflected in our statements of cash flows) in the year ended December 31, 2025 was a surplus of $70.1 million compared to a deficit of $53.9 million in 2024.

Cash Flows from Investing Activities

We had cash flows used in investing activities of $1.3 billion and $1.7 billion during the years ended December 31, 2025 and 2024, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs. During 2025 and 2024, we added 80.7 and 90.7 net wells to production, respectively, excluding already producing wells from acquisitions.

Our cash flows used in investing activities reflects actual cash spending, which can lag several months from when the related costs were incurred. As a result, our actual cash spending is not always reflective of current levels of development activity. For instance, during the year ended December 31, 2025, our capitalized costs incurred, excluding non-cash consideration, for oil and natural gas properties (e.g., drilling and completion costs, acquisitions, and other capital expenditures) amounted to $1.2 billion, while the actual cash spend in this regard amounted to $1.3 billion.

Development and acquisition activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns. Our cash spend for development and acquisition activities for the years ended December 31, 2025 and 2024 are summarized in the following table:

	Year Ended December 31,	
(In millions)	**2025**	**2024**
Drilling and Development Capital Expenditures	$ 919.2	$ 771.3
Acquisition of Oil and Natural Gas Properties	328.0	900.2
Other Capital Expenditures	4.5	3.2
Total	$ 1,251.7	$ 1,674.6

Cash Flows from Financing Activities

Net cash used for financing activities was $247.5 million in the year ended December 31, 2025. The net cash used in financing activities in 2025 was primarily due to $695.2 million spent as part of the tender offer to repurchase certain of our Senior Notes due 2028 (inclusive of tender premiums), $600.0 million in repayments of borrowings under our Revolving Credit Facility, $173.4 million in dividend payments, $57.0 million in repurchases of common stock, $26.1 million spent in debt issuance costs, and $16.9 million from the entry into additional capped call transactions, partially offset by $725.0 million received from the issuance of our Senior notes due 2033, $388.0 million received from borrowing under our credit facility, and $211.2 million received from the issuance of the Additional Convertible Notes.

In the year ended December 31, 2024, our financing activities resulted in net cash provided of $266.8 million. The cash provided by financing activities in 2024 was primarily related to $984.0 million in increased borrowings under our Revolving Credit Facility, partially offset by $455.0 million in repayments of borrowing under our Revolving Credit Facility, $94.5 million in repurchases of common stock, and $162.0 million in dividend payments to holders of our common stock.

Revolving Credit Facility

We have entered into a revolving credit facility with Wells Fargo Bank, as administrative agent, and the lenders from time to time party thereto (the "Revolving Credit Facility"). The Revolving Credit Facility is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to our oil and natural gas properties. Subsequent to December 31, 2025, in February 2026, the Company completed a wildcard redetermination, pursuant to which the borrowing base was increased from $1.8 billion to $1.975 billion and the elected commitment amount was increased from $1.6 billion to $1.8 billion. As of December 31, 2025, we had $478.0 million in borrowings outstanding under the facility, leaving approximately $1.3 billion in available committed borrowing capacity. See Note 4 to our financial statements for further details regarding the Revolving Credit Facility.

Senior Notes due 2028

As of December 31, 2025, we had outstanding $20.2 million aggregate principal amount of our Senior Notes due 2028. See Note 4 to our financial statements for further details regarding the Senior Notes due 2028. Subsequent to December 31, 2025, in February 2026, we gave notice to the holders of the Senior Notes due 2028 (the "Notice of Full Redemption") that we elected to redeem all of the outstanding Senior Notes due 2028, in accordance with the terms of the 2028 Notes Indenture. Pursuant to the Notice of Full Redemption, the Redemption Date is March 4, 2026, and the Redemption Price is 100%.

Convertible Notes due 2029

As of December 31, 2025, we had outstanding $700.0 million aggregate principal amount of our Convertible Notes due 2029. See Note 4 to our financial statements for further details regarding the Convertible Notes.

Senior Notes due 2031

As of December 31, 2025, we had outstanding $500.0 million aggregate principal amount of our Senior Notes due 2031. See Note 4 to our financial statements for further details regarding the Senior Notes due 2031.

Senior Notes due 2033

As of December 31, 2025, we had outstanding $725.0 million aggregate principal amount of our Senior Notes due 2033. See Note 4 to our financial statements for further details regarding the Senior Notes due 2033.

Known Contractual and Other Obligations; Planned Capital Expenditures

Contractual and Other Obligations. We have contractual commitments under our debt agreements, including interest payments and principal repayments. See Note 4 to our financial statements. We have contractual commitments that may require us to make payments upon future settlement of our commodity derivative contracts. See Note 12 to our financial statements. We have future obligations related to the abandonment of our oil and natural gas properties. See Note 9 to our financial statements. With respect to all of these items, except for our commitments under our debt agreements, we cannot determine with accuracy the amount and/or timing of such payments.

Planned Capital Expenditures. For 2026, we are budgeting approximately $0.9 billion to $1.1 billion in total planned capital expenditures, including development expenditures and our smaller day-to-day acquisition activity, which we refer to as our "ground game" acquisition activity. As of December 31, 2025, we had incurred $328.9 million in capital expenditures that were included in accounts payable and accrued liabilities, and we estimate that we were committed to an additional approximately $430.6 million in development capital expenditures not yet incurred for wells we had elected to participate in. We expect to fund planned capital expenditures with cash generated from operations and, if required, borrowings under our Revolving Credit Facility. The foregoing excludes larger acquisitions, which are typically not included in our annual capital expenditure budget. See also "Capital Requirements" below.

Capital Stock and Debt Security Repurchases. In May 2022, the Company's board of directors approved a stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. In July 2024, the Company's board of directors terminated the prior stock repurchase program, and approved a new stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. On March 10, 2025, the Company's board of directors approved and promptly announced an additional $100.0 million authorization under this stock repurchase program. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions. During the year ended December 31, 2025 the Company repurchased 1,948,996 shares of its common stock under the stock repurchase programs at a total cost of $57.3 million (including commissions and $0.3 million in excise tax). The Company may in the future engage in similar transactions.

The amount, timing and allocation of capital expenditures are largely discretionary and subject to change based on a variety of factors. If oil, natural gas and NGL prices decline below our acceptable levels, or costs increase above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We will carefully monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, fluctuations in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control. For additional information on the impact of changing prices and market conditions on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Capital Requirements

Development and acquisition activities are discretionary, and, for the near term, we expect such activities to be maintained at levels we can fund through cash on hand, internal cash flow and borrowings under our Revolving Credit Facility. To the extent capital requirements exceed internal cash flow and borrowing capacity under our Revolving Credit Facility, additional financings from the capital markets may be pursued to fund these requirements. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and also between our projects, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. Our future success in growing proved reserves and production may be dependent on our ability to access outside sources of capital. If internally generated cash flow and borrowing capacity under our Revolving Credit Facility are not available or sufficient, we may issue additional equity or debt to fund capital expenditures, make acquisitions, extend maturities or to repay debt.

Satisfaction of Our Cash Obligations for the Next Twelve Months

With our Revolving Credit Facility and our cash flows from operations, we believe we will have sufficient capital to meet our drilling commitments, expected general and administrative expenses and other cash needs for the next twelve months and, based on current expectations, for the foreseeable future. Nonetheless, any strategic acquisition of assets or increase in drilling activity may lead us to seek additional capital. We may also choose to seek additional capital rather than utilize our Revolving Credit Facility or other debt instruments to fund accelerated or continued drilling at the discretion of management and depending on prevailing market conditions. We will evaluate any potential opportunities for acquisitions as they arise. However, there can be no assurance that any additional capital will be available to us on favorable terms or at all.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Based on current conditions and expectations, we are not presently budgeting for any material change in per well drilling and completion and other associated costs in 2026 compared to 2025.

Critical Accounting Estimates

The establishment and consistent application of accounting policies is a vital component of accurately and fairly presenting our financial statements in accordance with generally accepted accounting principles in the United States (GAAP), as well as ensuring compliance with applicable laws and regulations governing financial reporting. While there are rarely alternative methods or rules from which to select in establishing accounting and financial reporting policies, proper application often involves significant judgment regarding a given set of facts and circumstances and a complex series of decisions.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect our reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our estimates of our proved oil and natural gas reserves, future development costs, estimates relating to certain oil and natural gas revenues and expenses, and fair value of derivative instruments are the most critical to our financial statements.

Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Approximately 26% of our proved oil and gas reserve volumes are categorized as proved undeveloped reserves as of December 31, 2025. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserve, future cash flows from our reserves, and future development of our proved undeveloped reserves.

The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Such information includes revisions of certain reserve estimates attributable to our properties included in the prior year's estimates. These revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in oil and natural gas prices.

Our third-party independent reserve engineers, Cawley, audited 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2025. Our estimates of proved reserves quantities were prepared in accordance with the rules promulgated by the SEC. In connection with our external petroleum engineers performing their independent reserve audits, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests.

Oil and Natural Gas Properties

The method of accounting we use to account for our oil and natural gas investments determines what costs are capitalized and how these costs are ultimately matched with revenues and expensed.

We utilize the full cost method of accounting to account for our oil and natural gas investments instead of the successful efforts method because we believe it more accurately reflects the underlying economics of our programs to explore and develop oil and natural gas reserves. The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs, geological and geophysical costs that are directly attributable to the properties and capitalized interest. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. The full cost method differs from the successful efforts method of accounting for oil and natural gas investments. The primary difference between these two methods is the treatment of exploratory dry hole costs. These costs are generally expensed under the successful efforts method when it is determined that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are initially capitalized and classified as unproved properties pending determination of proved reserves. If no proved reserves are discovered, these costs are then amortized with all the costs in the full cost pool.

Capitalized amounts except unproved costs are depleted using the units of production method. The depletion expense per unit of production is the ratio of the sum of our unamortized historical costs and estimated future development costs to our proved reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting periods. For the year ended December 31, 2025, our average depletion expense per unit of production was $16.43 per Boe.

To the extent the capitalized costs in our full cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the sum of the present value (using a 10% discount rate and based on 12-month/SEC oil and natural gas prices) of the estimated future net cash flows from our proved oil and natural gas reserves and the capitalized cost associated with our unproved properties, we would have a non-cash ceiling impairment. Such impairment costs would be charged to operations as a reduction of the carrying value of oil and natural gas properties. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed, even if the low prices are temporary. In addition, ceiling impairment charges may occur if we experience poor drilling results or if estimations of our proved reserves are substantially reduced. A ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once recognized, a ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date.

At December 31, 2025, we performed an impairment review using prices that reflect an average of 2025's monthly prices as prescribed pursuant to the SEC's guidelines. As a result, we recorded a non-cash impairment charge of $702.7 million in the year ended December 31, 2025. We did not record any full cost impairment charge for the year ended December 31, 2024. Average commodity prices have declined in recent months. If this downward trend continues, and/or if our proved reserves decrease significantly in future months, the present value of the Company's future net revenues could decline significantly, which could trigger the need for the Company to record a non-cash ceiling test impairment of its oil and gas property costs in future periods.

Derivative Instrument Activities

We use derivative instruments from time to time to manage market risks resulting primarily from fluctuations in the prices of oil and natural gas. We may periodically enter into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. We may also use exchange traded futures contracts and option contracts to hedge the delivery price of oil at a future date.

All derivative positions are carried at their fair value in the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses on unsettled derivatives, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of accumulated other comprehensive income or other income (expense). The resulting cash flows from derivatives are reported as cash flows from operating activities. See Note 12 to our financial statements for a description of the derivative contracts.

Recently Issued or Adopted Accounting Pronouncements

See Note 2 to the financial statements for a discussion of recently issued or adopted accounting pronouncements.

Off-Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

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

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and we believe these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices. See "Item 2. Properties - Proved Reserves Sensitivity by Price Scenario" for estimates of how a change in oil and gas prices from the 2025 SEC Case to either the $50 Flat Case or the $70 Flat Case would impact our proved reserves volumes and the associated PV-10 values.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to commodity price volatility. All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of other comprehensive income or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility.

The following table summarizes our open crude oil derivative contracts as of December 31, 2025, by fiscal quarter.

Crude Oil Contracts

	Swaps[(1)]		Collars			
Contract Period	Volume (Bbls)	Weighted Average Price ($/Bbl)	Volume Ceiling (Bbls)	Volume Floor (Bbls)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Floor Price ($/Bbl)
2026:						
Q1	2,291,876	$ 68.34	3,121,226	2,446,789	$ 72.98	$ 62.94
Q2	1,930,956	66.44	2,245,907	1,563,977	71.35	63.55
Q3	1,494,567	68.93	1,810,587	1,121,163	72.33	65.01
Q4	1,494,567	68.91	1,810,587	1,121,163	72.33	65.01

(1) This table does not include volumes subject to swaptions and call options, which are crude oil derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. This table also does not include basis swaps. See Note 12 to our financial statements for further details regarding our commodity derivatives, including the swaptions and call options that are not included in the foregoing table.

The following table summarizes our open natural gas derivative contracts as of December 31, 2025, by fiscal quarter.

Natural Gas Contracts

Contract Period	Swaps[(1)] Volume (MMBTU)	Swaps[(1)] Weighted Average Price ($/MMBTU)	Collars Volume Ceiling (MMBTU)	Collars Volume Floor (MMBTU)	Collars Weighted Average Ceiling Price ($/MMBTU)	Collars Weighted Average Floor Price ($/MMBTU)
2026:						
Q1	11,130,000	$ 4.08	12,203,249	12,203,249	$ 4.93	$ 3.39
Q2	12,420,000	3.97	12,924,706	12,924,706	4.96	3.42
Q3	12,420,000	4.01	12,924,706	12,924,706	4.92	3.45
Q4	14,415,000	4.14	12,889,642	12,889,642	5.10	3.47
2027:						
Q1	9,350,000	$ 4.02	6,965,000	6,965,000	$ 4.79	$ 3.46
Q2	9,660,000	4.01	5,980,000	5,980,000	4.43	3.45
Q3	9,660,000	4.01	5,980,000	5,980,000	4.43	3.45
Q4	7,485,000	3.98	4,275,000	4,275,000	4.41	3.45
2028:						
Q1	2,555,000	$ 3.83	900,000	900,000	$ 4.17	$ 3.50
Q2	1,840,000	3.83	920,000	920,000	4.17	3.50
Q3	1,840,000	3.83	920,000	920,000	4.17	3.50
Q4	1,530,000	3.85	920,000	920,000	4.07	3.50
2029:						
Q1	—	$ —	890,000	890,000	$ 3.88	$ 3.50
Q2	—	—	920,000	920,000	3.88	3.50
Q3	—	—	920,000	920,000	3.88	3.50
Q4	—	—	610,000	610,000	3.88	3.50

(1) This table does not include volumes subject to swaptions and call options, which are natural gas derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. This table also does not include basis swaps. See Note 12 to our financial statements for further details regarding our commodity derivatives, including the call options and basis swaps that are not included in the foregoing table.

The following table summarizes our open NGL derivative contracts as of December 31, 2025, by fiscal quarter.

NGL Contracts

Contract Period	Swaps	
	Volume (BBL)	Weighted Average Price ($/BBL)
2026:		
Q1	92,250	$ 36.00
Q2	106,925	33.32
Q3	96,600	33.03
Q4	80,500	33.32
2027:		
Q1	65,250	$ 32.30
Q2	59,150	30.73
Q3	57,500	30.69
Q4	52,900	30.87

Interest Rate Risk

Our long-term debt as of December 31, 2025 was comprised of borrowings that contain fixed and floating interest rates. Our Senior Notes due 2028, Senior Notes due 2031, Senior Notes due 2033 and Convertible Notes bear cash interest at fixed rates. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement (see Note 4 to our financial statements).

From time to time, the Company may use interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. The following table summarizes our open interest rate derivative contracts as of December 31, 2025.

Fixed Rate Swap Agreements (in thousands)

Contract Period	Swaps		
	Notional Amount	Fixed Rate	Floating Benchmark
October 1, 2024 - October 1, 2026	$ 25,000	3.423 %	USD-SOFR CME
May 1, 2025 - May 1, 2027	$ 50,000	3.423 %	USD-SOFR CME
September 19, 2025 - October 1, 2027	$ 50,000	3.300 %	USD-SOFR CME
October 20, 2025 - November 1, 2027	$ 100,000	3.187 %	USD-SOFR CME
December 10, 2025 - December 1, 2027	$ 50,000	3.393 %	USD-SOFR CME
December 10, 2025 - December 1, 2028	$ 50,000	3.392 %	USD-SOFR CME

Changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt outstanding at December 31, 2025 would cost us approximately $1.5 million in additional annual interest expense.

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

The financial statements and supplementary financial information required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F-1.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures.

As of December 31, 2025, our management, including our principal executive officer and principal financial officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our principal executive officer and principal financial officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of December 31, 2025.

Changes in Internal Control over Financial Reporting

No change in our Company’s internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2025, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management’s Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is a process designed by or under the supervision of the Company's principal executive officer and principal financial officer and effected by the board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles. The 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 issuer are being made only in accordance with authorizations of management and directors of the issuer; 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.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013).

Based on our evaluation under the framework in Internal Control-Integrated Framework, management concluded that the Company’s internal control over financial reporting was effective as of December 31, 2025.

The effectiveness of our Company’s internal control over financial reporting as of December 31, 2025, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Northern Oil & Gas, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Northern Oil & Gas, Inc. (the "Company") as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the financial statements as of and for the year ended December 31, 2025, of the Company and our report dated February 26, 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 Annual 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/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 26, 2026

Item 9B. ***Other Information***

(a) None.

(b) During the quarter ended December 31, 2025, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

Not applicable.

PART III

Certain information required by this Part III is incorporated by reference from our definitive Proxy Statement for the Annual Meeting of Stockholders to be held in 2026, which we intend to file with the SEC pursuant to Regulation 14A within 120 days after December 31, 2025. Except for those portions specifically incorporated into this Annual Report on Form 10-K by reference to the Proxy Statement, no other portions of the Proxy Statement are deemed to be filed as part of this Annual Report on Form 10-K.

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information appearing under the headings "Proposal 1: Election of Directors," "Corporate Governance" and "Delinquent Section 16(a) Reports" in the Proxy Statement is incorporated herein by reference.

We have adopted a Code of Business Conduct and Ethics that applies to our chief executive officer, chief financial officer and persons performing similar functions. A copy is available on our website at www.noginc.com. We intend to post on our website any amendments to, or waivers from, our Code of Business Conduct and Ethics pursuant to the rules of the SEC and New York Stock Exchange.

We have adopted an Insider Trading Policy governing the purchase, sale and/or other dispositions of our securities by our directors, officers and employees. A copy of the Insider Trading Policy is filed as an exhibit to this Annual Report on Form 10-K.

Information About Our Executive Officers

Our executive officers, their ages and offices held are as follows:

Name	Age	Positions
Nicholas O'Grady	47	Chief Executive Officer
Chad Allen	44	Chief Financial Officer
Adam Dirlam	42	President
Erik Romslo	48	Chief Legal Officer & Secretary
James Evans	42	Chief Technical Officer

Nicholas O'Grady has served as our Chief Executive Officer since January 2020 and has served as a member of the Company's board of directors since December 2024. Prior to that, he served as our Chief Financial Officer from June 2018 to September 2019, and as our Chief Financial Officer & President from September 2019 to December 2019. Mr. O'Grady has approximately two decades of finance experience, both as an investment banker and as a principal investor. Mr. O'Grady began his career in the Natural Resources investment banking group at Bank of America. Later moving to the hedge fund industry, he worked at firms such as Highbridge Capital Management. Prior to joining our company, he worked as a senior credit analyst and portfolio manager at Hudson Bay Capital Management from September 2014 to May 2018, where he focused on energy-related equities, public credit, private and direct investments. Previously, he worked as a portfolio manager at Bluecrest Capital Management from November 2013 to June 2014, and at Sigma Capital Management from April 2012 to October 2013. Mr. O'Grady holds a bachelor's degree in both history and economics from Bowdoin College.

Chad Allen has served as our as our Chief Financial Officer since January 2020. Prior to that, he served as our Chief Accounting Officer from August 2016 to December 2019, prior to which he served as the company's Corporate Controller since joining NOG in August of 2013. Mr. Allen served as the company's Interim Chief Financial Officer from January-May 2018. Prior to joining our company, Mr. Allen was in the audit practice with Grant Thornton LLP from 2010 to 2013, and in the audit practice at RSM US LLP (formerly McGladrey & Pullen, LLP) from 2004 to 2010. Mr. Allen holds a bachelor's degree in accounting from Minnesota State University, Mankato and is a Certified Public Accountant.

Adam Dirlam has served as our President since December 2021 prior to which he served as our Chief Operating Officer since January 2020. Prior to that, he served as our Executive Vice President – Land & Operations since June 2018, prior to which he served as the company's Senior Vice President of Land & Operations since 2013 and other various roles with the company since 2009. Prior to joining our company, Mr. Dirlam served in various finance and accounting roles for Honeywell International. Mr. Dirlam holds a bachelor's degree from the University of St. Thomas and a master's degree from the University of Minnesota - Carlson School of Management.

Erik Romslo has served as our Chief Legal Officer and Secretary since January 2020. Prior to that, he served as our General Counsel and Secretary from October 2011 to December 2019 and as an Executive Vice President from January 2013 to December 2019. Prior to joining our company, Mr. Romslo practiced law in the Minneapolis office of Faegre Drinker Biddle & Reath LLP (formerly Faegre & Benson LLP), from 2005 until 2011, where he was a member of the Corporate group. Prior to joining Faegre, Mr. Romslo practiced law in the New York City office of Fried, Frank, Harris, Shriver & Jacobson LLP. Mr. Romslo holds a bachelor's degree from St. Olaf College and a law degree from the New York University School of Law.

James Evans has served as our Chief Technical Officer since April 2023. Prior to that, he served as our Executive Vice President and Chief Engineer since February 2021, our Senior Vice President of Engineering since January 2020 and as Vice President of Engineering since June 2018, prior to which he had served as the company's Reservoir Engineering Manager since 2015. Mr. Evans began his career as a Reservoir Engineer with Cabot Oil & Gas, and also worked for Cornerstone Natural Resources and Fidelity Exploration before joining our company. Mr. Evans holds a bachelor's degree in Petroleum Engineering from Montana Tech.

Item 11. *Executive Compensation*

The information appearing under the headings "Executive Compensation" and "Compensation Committee Report," and the information regarding compensation committee interlocks and insider participation under the heading "Corporate Governance," in the Proxy Statement is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information with respect to our common shares issuable under our equity compensation plans as of December 31, 2025:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders			
Amended and Restated 2018 Equity Incentive Plan	700,852 (1)	—	1,897,358
Equity compensation plans not approved by security holders	—	—	—
Total	700,852	$ —	1,897,358

(1) Represents shares issuable pursuant to performance-based restricted stock units ("RSUs") granted under the Company's Amended and Restated 2018 Equity Incentive Plan (the "2018 Plan"), assuming actual or maximum performance under the terms of the RSUs. This figure does not include the shares potentially issuable in settlement of appreciation rights ("SARs") issued pursuant to the 2018 Plan, as the awards are not denominated in securities and the number of securities that may be issued in settlement of the SARs is not known. See Note 6 to our financial statements for additional information on these awards.

The information appearing under the heading "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information appearing under the headings "Certain Relationships and Related Transactions" and "Corporate Governance" in the Proxy Statement is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services***

The information appearing under the headings "Registered Public Accountant Fees" and "Pre-Approval Policies and Procedures of Audit Committee" in the Proxy Statement is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) Documents filed as part of this Report:

1 *Financial Statements*
See Index to Financial Statements on page F-1.

2 *Financial Statement Schedules*
All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the financial statements or notes thereto.

(b) Exhibits:

Exhibit No.	Description	Reference
2.1*	Acquisition and Cooperation Agreement, dated as of June 27, 2024, by and between SM Energy Company and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.2 to SM Energy Company's Current Report on Form 8-K (File No. 001-31539) filed with the SEC on June 28, 2024
2.2*	Purchase and Sale Agreement, dated as of June 27, 2024, by and among XCL AssetCo, LLC, XCL Marketing, LLC, Wasatch Water Logistics, LLC, XCL Resources, LLC and XCL SandCo, LLC, as seller, SM Energy Company, as purchaser, and Northern Oil and Gas, Inc. (solely for the purposes of ratifying certain provisions therein)	Incorporated by reference to Exhibit 10.1 to SM Energy Company's Current Report on Form 8-K (File No. 001-31539) filed with the SEC on June 28, 2024
2.3*	Purchase and Sale Agreement, dated as of December 5, 2025, by and among Antero Resources Corporation, Antero Minerals LLC and Monroe Pipeline LLC, as sellers, and Infinity Natural Resources, LLC and Northern Oil and Gas, Inc., as buyers	Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on December 8, 2025
2.4*	Purchase and Sale Agreement, dated as of December 5, 2025, by and among Antero Midstream LLC, Antero Water LLC and Antero Treatment LLC, as sellers, and Infinity Natural Resources, LLC and Northern Oil and Gas, Inc., as buyers	Incorporated by reference to Exhibit 2.2 to the Registrant's Current Report on Form 8-K filed with the SEC on December 8, 2025
3.1	Restated Certificate of Incorporation of Northern Oil and Gas, Inc. dated August 24, 2018	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018
3.2	Certificate of Amendment to the Restated Certificate of Incorporation of Northern Oil and Gas, Inc. dated September 18, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 24, 2020
3.3	Certificate of Amendment to the Restated Certificate of Incorporation of Northern Oil and Gas, Inc. dated May 23, 2024	Incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on July 31, 2024
3.4	Amended and Restated Bylaws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 20, 2023
4.1	Description of Northern Oil and Gas, Inc. Capital Stock	Filed herewith
4.2	Indenture, dated February 18, 2021, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.125% Senior Note due 2028)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on February 23, 2021
4.3	First Supplemental Indenture, dated November 15, 2021, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the SEC on November 15, 2021
4.4	Indenture, dated October 14, 2022, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 3.625% Convertible Senior Note due 2029)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 17, 2022
4.5	First Supplemental Indenture, dated June 17, 2025, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the SEC on June 18, 2025

4.6	Indenture, dated May 15, 2023, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.750% Senior Note due 2031)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 19, 2023
4.7	Indenture, dated October 1, 2025, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 7.875% Senior Note due 2033)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 1, 2025
10.1	Letter Agreement, dated July 21, 2017, by and between Northern Oil and Gas, Inc. and Bahram Akradi	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 24, 2017
10.2	Registration Rights Agreement, dated as of May 15, 2018, among Northern Oil and Gas, Inc. and the holders party thereto	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
10.3	Registration Rights Agreement, dated September 17, 2018, between Pivotal Williston Basin, LP, Pivotal Williston Basin II, LP, and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 18, 2018
10.4	Registration Rights Agreement, dated October 1, 2018, by and between WR Operating LLC and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 1, 2018
10.5#	Amended and Restated Employment Agreement, dated December 29, 2023, between Northern Oil and Gas, Inc. and Nicholas O'Grady	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 5, 2024
10.6#	Second Amended and Restated Employment Agreement, dated December 29, 2023, between Northern Oil and Gas, Inc. and Adam Dirlam	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on January 5, 2024
10.7#	Second Amended and Restated Employment Agreement, dated December 29, 2023, between Northern Oil and Gas, Inc. and Erik Romslo	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the SEC on January 5, 2024
10.8#	Second Amended and Restated Employment Agreement, dated December 29, 2023, between Northern Oil and Gas, Inc. and Chad Allen	Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed with the SEC on January 5, 2024
10.9#	Second Amended and Restated Employment Agreement, dated December 29, 2023, between Northern Oil and Gas, Inc. and James Evans	Incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on January 5, 2024
10.10#	Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 26, 2023
10.11#	Form of Restricted Stock Award Agreement (Time-Based Single Trigger) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.34 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 18, 2019
10.12#	Form of Restricted Stock Award Agreement (Time-Based Double Trigger) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.35 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 18, 2019
10.13#	Form of Restricted Stock Award Agreement (Performance-Based Employees) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.36 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 18, 2019
10.14#	Form of Restricted Stock Award Agreement (Performance-Based Directors) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.37 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 18, 2019
10.15#	Form of 2022 Performance Equity Award Agreement under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.23 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 24, 2023
10.16#	Form of December 2023 Performance-Based Restricted Stock Unit Award Agreement (Compound Annualized TSR) under the Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.18 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 23, 2024

10.17#	Form of December 2023 Performance-Based Share Appreciation Award Agreement under the Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.19 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 23, 2024
10.18#	Form of December 2023 Time-Based Restricted Stock Award Agreement under the Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.20 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 23, 2024
10.19#	Form of December 2023 Performance-Based Restricted Stock Unit Award Agreement (Relative TSR) under the Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on April 30, 2024
10.20#	Form of August 2024 Performance-Based Restricted Stock Unit Award Agreement (Compound Annualized TSR) under the Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on November 6, 2024
10.21#	Form of August 2024 Performance-Based Restricted Stock Unit Award Agreement (Relative TSR) under the Northern Oil and Gas, Inc. Amended and Restated 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on November 6, 2024
10.22	Purchase Agreement, dated June 12, 2025, by and between Northern Oil and Gas, Inc. and Morgan Stanley & Co. LLC, as representative of the several other initial purchasers named in Schedule 1 thereto.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on June 18, 2025
10.23	Fourth Amended and Restated Credit Agreement, dated as of November 5, 2025, among Northern Oil and Gas, Inc., Wells Fargo Bank, National Association, as administrative agent and collateral agent, and the lenders from time to time party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 10, 2025
10.24	Form of Capped Call Confirmation	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 17, 2022
10.25	Form of Capped Call Confirmation	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on June 18, 2025
19.1	Northern Oil and Gas, Inc. Insider Trading Policy	Incorporated by reference to Exhibit 19.1 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 20, 2025
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP	Filed herewith
23.2	Consent of Cawley, Gillespie & Associates, Inc.	Filed herewith
24.1	Powers of Attorney	Filed herewith
31.1	Certification of the Principal Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Principal Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith
97	Northern Oil and Gas, Inc. Clawback Policy	Incorporated by reference to Exhibit 97 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 23, 2024

99.1	Report of Cawley, Gillespie & Associates	Filed herewith
101.INS	XBRL Instance Document	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith
104	The cover page from Northern Oil and Gas, Inc. Annual Report on Form 10-K for the year ended December 31, 2025, formatted in Inline XBRL	Filed herewith

* Certain annexes, schedules and exhibits have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The Company undertakes to furnish supplemental copies of any of the omitted annexes, schedules and exhibits to the SEC upon its request.

\# Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report.

Item 16. ***Form 10-K Summary***

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHERN OIL AND GAS, INC.

Date: February 26, 2026 By: /s/ Nicholas O'Grady

Nicholas O'Grady, Chief Executive Officer; Principal Executive Officer

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

Signature	Title	Date
/s/ Nicholas O'Grady Nicholas O'Grady	Chief Executive Officer, Principal Executive Officer & Director	February 26, 2026
/s/ Chad Allen Chad Allen	Chief Financial Officer, Principal Financial & Accounting Officer	February 26, 2026
* Bahram Akradi	Director	February 26, 2026
* Lisa Bromiley	Director	February 26, 2026
* Ernie Easley	Director	February 26, 2026
* Michael Frantz	Director	February 26, 2026
* William Kimble	Director	February 26, 2026
* Stuart Lasher	Director	February 26, 2026
* Jennifer Pomerantz	Director	February 26, 2026

* Nicholas O'Grady, by signing his name hereto, does hereby sign this document on behalf of each of the above-named directors of the registrant pursuant to Powers of Attorney duly executed by such persons.

By /s/ Nicholas O'Grady
Nicholas O'Grady
Attorney-in-fact

NORTHERN OIL AND GAS, INC.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Northern Oil & Gas, Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Northern Oil & Gas, Inc. (the "Company") as of December 31, 2025 and 2024, the related 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 "financial statements"). In our opinion, the 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 have also 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 *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matter

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

Proved Oil and Natural Gas Properties – Oil and Natural Gas Reserves and the Impact to Full Cost Ceiling Test Impairment Calculation ("Ceiling Test") – Refer to Note 2 to the financial statements

Critical Audit Matter Description

The Company follows the full cost method of accounting for crude oil and natural gas operations. Therefore, the Company's proved oil and natural gas properties are depleted using the units-of-production method based upon production. The Company's proved oil and natural gas properties are evaluated for impairment at least quarterly in accordance with accounting principles generally accepted in the United States of America and SEC guidelines. The ceiling test involves a comparison of net capitalized costs to the sum of the present value of the estimated future net cash flows from the Company's oil and natural gas properties using a discount rate of 10%. The estimation of the Company's oil and natural gas reserves quantities and the related future net cash flows requires management to make significant estimates and assumptions since, as a non-operator, the Company has limited visibility into the timing of future production quantities associated with the five-year development plan. The Company's oil and natural gas reserve quantities and the related future net cash flows are audited by its third-party independent reserve engineers. Changes in these estimates, assumptions, or engineering data could have a significant impact on the depletion calculation and proved oil and natural gas properties impairment.

Given the significant judgments made by management relating to the estimates and assumptions required within the five-year development plan due to limited visibility as a non-operator regarding future production quantities, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities and the related future net cash flows required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions regarding oil and natural gas reserve quantities and the related future net cash flows associated with the five-year development plan included the following, among others:

- We tested the operating effectiveness of controls related to the Company's estimation of oil and natural gas reserve quantities and the related future net cash flows, including controls related to the five-year development plan.

- We evaluated the reasonableness of the future production quantities and the related future net cash flows associated with management's five-year development plan by comparing to:

    - Historical conversions of proved undeveloped oil and natural gas reserves into proved developed oil and natural gas reserves.
    - Internal communications to management and the Board of Directors.
    - Authorization and approval for expenditures.
    - External information regarding the ability of the operators of the oil and natural gas properties to develop proved undeveloped reserves considering current and forecasted liquidity of the operators obtained from publicly available information, level of drilling activity by operators in areas where the Company holds leasehold interests, and length of time required to drill and complete wells.
    - Company's expected availability of capital relative to the five-year development plan.

- We evaluated the Company's estimates of future production volumes by completing a retrospective comparison to historical production.

- We evaluated the estimate of operating costs used in the forecast at year-end and compared to historical operating costs.

- We evaluated the experience, qualifications, and objectivity of the Company's engineers responsible for the auditing of the reserve estimates and assumptions and engineering data. We made inquiries of those reserve engineers regarding the process utilized and judgments made to audit the Company's estimates of oil and natural gas reserves.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 26, 2026

We have served as the Company's auditor since 2018.

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

(In thousands, except par value and share data)	December 31, 2025	December 31, 2024
Assets		
Current Assets:		
Cash and Cash Equivalents	$ 14,299	$ 8,933
Accounts Receivable, Net	349,927	389,673
Advances to Operators	29,996	12,291
Prepaid Expenses and Other	7,065	5,271
Derivative Instruments	166,678	46,525
Income Tax Receivable	18,066	38,050
Total Current Assets	586,031	500,743
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	11,441,786	10,307,376
Unproved	86,034	42,702
Less – Accumulated Depletion and Impairment	(6,784,649)	(5,271,807)
Total Oil and Natural Gas Properties, Net	4,743,171	5,078,271
Other Property and Equipment, Net	3,196	3,899
Total Property and Equipment, Net	4,746,367	5,082,170
Derivative Instruments	3,036	9,832
Other Noncurrent Assets	73,941	11,077
Total Assets	$ 5,409,375	$ 5,603,822
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts Payable	$ 218,620	$ 202,866
Accrued Liabilities	293,779	290,792
Accrued Interest	23,018	25,992
Derivative Instruments	—	19,915
Other Current Liabilities	3,876	4,705
Total Current Liabilities	539,293	544,270
Long-term Debt, Net	2,395,393	2,369,294
Derivative Instruments	48,102	93,606
Deferred Tax Liability	247,645	228,038
Asset Retirement Obligations	50,831	45,907
Other Noncurrent Liabilities	1,770	2,272
Total Liabilities	$ 3,283,034	$ 3,283,387
Commitments and Contingencies		
Common Stock, par value $0.001; 270,000,000 authorized; 97,265,559 shares outstanding at 12/31/2025 270,000,000 authorized; 99,113,645 shares outstanding at 12/31/2024	499	501
Additional Paid-In Capital	1,644,563	1,877,416
Retained Earnings	481,279	442,518
Total Stockholders' Equity	2,126,341	2,320,435
Total Liabilities and Stockholders' Equity	$ 5,409,375	$ 5,603,822

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

NORTHERN OIL AND GAS, INC.
STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024, AND 2023

	December 31,		
(In thousands, except share and per share data)	**2025**	**2024**	**2023**
Revenues			
Oil and Gas Sales	$ 2,081,288	$ 2,152,079	$ 1,897,779
Gain on Commodity Derivatives, Net	380,664	61,967	259,250
Other Revenue	13,771	11,682	9,230
Total Revenues	2,475,723	2,225,728	2,166,259
Operating Expenses			
Production Expenses	473,666	429,792	347,006
Production Taxes	131,334	157,091	160,118
General and Administrative Expenses	61,332	50,463	46,801
Depletion, Depreciation, Amortization and Accretion	814,859	740,901	486,024
Impairment of Oil and Gas Assets	702,747	—	—
Legal Settlement Expenses	33,090	—	—
Other Expenses	12,848	9,650	4,448
Total Operating Expenses	2,229,876	1,387,897	1,044,397
Income From Operations	245,847	837,831	1,121,862
Other Income (Expense)			
Interest Expense	(172,380)	(157,717)	(135,664)
Gain (Loss) on Unsettled Interest Rate Derivatives, Net	(566)	263	(1,017)
Gain (Loss) on the Extinguishment of Debt, Net	(10,833)	—	659
Contingent Consideration Gain	—	—	10,107
Other Income	637	440	4,795
Total Other Expense	(183,142)	(157,014)	(121,120)
Income Before Income Taxes	62,705	680,817	1,000,742
Income Tax Expense	23,944	160,509	77,773
Net Income Attributable to Common Stockholders	$ 38,761	$ 520,308	$ 922,969
Net Income Per Common Share – Basic	$ 0.40	$ 5.21	$ 10.09
Net Income Per Common Share – Diluted	$ 0.39	$ 5.14	$ 10.03
Weighted Average Common Shares Outstanding – Basic	97,711,444	99,852,539	91,483,687
Weighted Average Common Shares Outstanding – Diluted	99,314,382	101,267,625	92,060,947

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

NORTHERN OIL AND GAS, INC.
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024, AND 2023

	December 31,		
(In thousands)	2025	2024	2023
Cash Flows From Operating Activities			
Net Income	$ 38,761	$ 520,308	$ 922,969
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depletion, Depreciation, Amortization and Accretion	814,859	740,901	486,024
Impairment of Oil and Gas Assets	702,747	—	—
Amortization of Debt Issuance Costs	10,595	9,411	8,096
Loss (Gain) on Extinguishment of Debt	10,833	—	(659)
Amortization of Bond Premium on Long-term Debt	(2,218)	(1,143)	(1,475)
Deferred Income Taxes	23,570	159,550	76,858
Unrealized (Gain) Loss on Derivative Instruments	(178,777)	20,995	(200,314)
Gain on Contingent Consideration	—	—	(10,107)
Share-Based Compensation Expense	15,363	11,969	5,660
Other	(508)	558	2,404
Changes in Working Capital and Other Items:			
Accounts Receivable, Net	39,746	(17,367)	(101,317)
Prepaid and Other Expenses	(1,571)	(1,498)	(474)
Accounts Payable and Accrued Liabilities	14,878	3,759	(6,081)
Accrued Interest	(2,974)	(227)	1,738
Settlement Difference for Asset Retirement Obligations	—	(3,752)	—
Income Tax Receivable	19,984	(34,801)	—
Net Cash Provided By Operating Activities	1,505,288	1,408,663	1,183,321
Cash Flows From Investing Activities			
Acquisitions of and Capital Expenditures on Oil and Natural Gas Properties	(1,251,703)	(1,674,626)	(1,861,134)
Purchases of Other Property and Equipment	(759)	(128)	(1,212)
Net Cash Used For Investing Activities	(1,252,462)	(1,674,754)	(1,862,346)
Cash Flows From Financing Activities			
Advances on Revolving Credit Facility	388,000	984,000	998,224
Repayments on Revolving Credit Facility	(600,000)	(455,000)	(1,156,224)
Purchase of Capped Call	(16,947)	—	—
Premium Received on Convertible Notes	11,194	—	—
Issuance of Convertible Notes	200,000	—	—
Issuance of Senior Notes due 2033	725,000	—	492,840
Repurchase of Senior Notes due 2028	(684,943)	—	(18,436)
Debt Issuance Costs Paid	(26,146)	(1,917)	(11,896)
Tender Premium Paid on Repurchase of Senior Notes due 2028	(10,274)	—	—
Issuance of Common Stock	—	—	514,749
Common Stock Dividends Paid	(173,404)	(161,969)	(123,945)
Repurchases of Common Stock	(57,012)	(94,497)	(8,004)
Excise Tax on Repurchases of Common Stock	(788)	—	—
Restricted Stock Surrenders - Tax Obligations	(2,140)	(3,788)	(2,616)
Net Cash Provided By (Used In) Financing Activities	(247,460)	266,829	684,692
Net Increase in Cash and Cash Equivalents	5,366	738	5,667
Cash and Cash Equivalents – Beginning of Period	8,933	8,195	2,528
Cash and Cash Equivalents – End of Period	$ 14,299	$ 8,933	$ 8,195

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

NORTHERN OIL AND GAS, INC.
STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024, AND 2023

(In thousands, except share data)	Common Stock		Additional Paid-In	Retained Earnings	Total Stockholders'
	Shares	Amount	Capital	(Deficit)	Equity
December 31, 2022	85,165,807	$ 487	$ 1,745,532	$ (1,000,759)	$ 745,260
Share Based Compensation	468,268	—	5,994	—	5,994
Equity Offerings, net of Issuance Costs	15,122,500	15	514,734	—	514,749
Restricted Stock Surrenders - Tax Obligations	(98,052)	—	(2,616)	—	(2,616)
Repurchases of Common Stock	(287,751)	—	(8,004)	—	(8,004)
Restricted Stock Forfeitures	(13,404)	—	(54)		(54)
Common Stock Warrant Exchange Agreement - Veritas Warrants	403,780	—	—	—	—
Deferred Taxes Related to Capped Calls	—	—	8,370	—	8,370
Common Stock Dividends Declared	—	—	(138,992)	—	(138,992)
Net Income	—	—	—	922,969	922,969
December 31, 2023	100,761,148	$ 503	$ 2,124,963	$ (77,790)	$ 2,047,676
Restricted Stock Forfeitures	(424)	—	(2)	—	(2)
Share Based Compensation	225,773	—	11,971	—	11,972
Restricted Stock Surrenders - Tax Obligations	(101,415)	—	(3,788)	—	(3,788)
Acquisitions of Oil and Natural Gas Properties	107,657	—	3,737	—	3,737
Issuance of Common Stock in Exchange for Warrants	656,297	—	—	—	—
Repurchases of Common Stock	(2,535,391)	(2)	(95,439)	—	(95,441)
Common Stock Dividends Declared	—	—	(164,026)	—	(164,026)
Net Income	—	—	—	520,308	520,308
December 31, 2024	99,113,645	$ 501	$ 1,877,416	$ 442,518	$ 2,320,435
Restricted Stock Forfeitures	(9,246)	—	(59)	—	(59)
Share Based Compensation	190,403	—	15,633	—	15,633
Restricted Stock Surrenders - Tax Obligations	(80,247)	—	(2,140)	—	(2,140)
Entry into Additional Capped Call Transactions, Net of Deferred Tax Impact	—	—	(12,985)	—	(12,985)
Repurchases of Common Stock	(1,948,996)	(2)	(57,268)	—	(57,270)
Common Stock Dividends Declared	—	—	(176,034)	—	(176,034)
Net Income	—	—	—	38,761	38,761
December 31, 2025	97,265,559	$ 499	$ 1,644,563	$ 481,279	$ 2,126,341

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

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2025

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "NOG," "our" and words of similar import), a Delaware corporation, is an independent energy company engaged as a non-operator in the acquisition, exploration, development and production of oil and natural gas properties in the United States, primarily in the Williston Basin, the Permian Basin, the Appalachian Basin, and the Uinta Basin. The Company's common stock trades on the New York Stock Exchange under the symbol "NOG".

The Company's principal business is crude oil and natural gas exploration, development, and production in the United States. The Company's primary strategy is investing in non-operated minority working and mineral interests in oil and natural gas properties, with a core area of focus in four premier basins within the United States.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

Out-of-Period Adjustments

During the year ended December 31, 2024, the Company identified certain errors in its previously issued financial statements that have been corrected through cumulative out-of-period adjustments in the financial statements as of and for the year ended December 31, 2024. The errors related, primarily, to improper classifications of income taxes withheld by the state of New Mexico, from January 2021 through June 2024, that were recorded as production tax expense. As a result, the Company recorded an out-of-period adjustment of approximately $32.1 million in the year ended December 31, 2024 to record an income tax receivable, offset by a reduction in production taxes. Further, in the year ended December 31, 2024, the Company recorded an out-of-period adjustment of approximately $6.7 million to income tax expense, offset by an increase in deferred tax liabilities. These errors understated net income for the fiscal years ended December 31, 2023, 2022, and 2021, by approximately $9.3 million, $11.2 million, and $0.5 million, respectively. Management considered qualitative and quantitative factors and concluded the out-of-period adjustments were immaterial to 2024 and each of the applicable periods.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The most significant estimates relate to proved crude oil and natural gas reserves, which include limited control over future development plans as a non-operator, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, acquisition date fair values of assets acquired and liabilities assumed, impairment of crude oil and natural gas properties, asset retirement obligations at initial recognition, and deferred income taxes.

Management's estimates and assumptions were based on historical data and consideration of future market conditions. Given the uncertainty inherent in any projection, actual results may differ from the estimates and assumptions used, and conditions may change, which could materially affect amounts reported in the financial statements.

Reclassifications

Certain prior period balances in the balance sheets, statements of cash flows, and statements of stockholders equity have been reclassified to conform to the current year presentation. Such reclassifications had no impact on net income, cash flows or stockholders' equity previously reported.

Cash and Cash Equivalents

The Company considers highly liquid investments with insignificant interest rate risk and original maturities to the Company of three months or less to be cash equivalents. Cash equivalents consist primarily of interest-bearing bank accounts. The

Company's cash positions represent assets held in checking and money market accounts. Cash and cash equivalents are generally available on a daily or weekly basis and are highly liquid in nature.

Accounts Receivable

Accounts receivables are carried on a gross basis, with no discounting. The Company's accounts receivable consists, primarily, of accrued receivables from crude oil, natural gas and NGL sales, as well as receivables from settled derivative instruments.

Advances to Operators

The Company participates in the drilling of crude oil and natural gas wells with other working interest partners. Due to the capital intensive nature of crude oil and natural gas drilling activities, the working interest partners responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid.

Other Property and Equipment

Property and equipment that are not crude oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives, ranging from three to seven years. Expenditures for replacements, renewals, and betterment are capitalized. Maintenance and repairs are charged to expense as incurred. Long-lived assets, other than crude oil and natural gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The accumulated depreciation related to Other Property and Equipment, Net was $5.3 million and $4.3 million as of December 31, 2025 and 2024, respectively. The Company has not recognized any impairment losses on non-crude oil and natural gas long-lived assets.

Oil and Natural Gas Properties

The Company follows the full cost method of accounting for its crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. Capitalized internal costs are summarized as follows for the years ended December 31, 2025, 2024 and 2023, respectively:

	December 31,		
(In thousands)	**2025**	**2024**	**2023**
Capitalized Certain Payroll and Other Internal Costs	$ 934	$ 788	$ 1,036
Capitalized Interest Costs	3,298	2,383	2,999
Total	$ 4,232	$ 3,172	$ 4,036

As of December 31, 2025, the Company held leasehold and other oil and gas interests in the United States in the Williston Basin, Permian Basin, Appalachian Basin and Uinta Basin.

Proceeds from property sales are generally credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool. In the years ended December 31, 2025, 2024 and 2023, there were no property sales that resulted in a significant alteration.

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 net book value of the oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The oil and natural gas properties, net balance was $4.7 billion and $5.1 billion as of December 31, 2025 and 2024, respectively. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing twelve-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives designated as hedges for accounting purposes, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded in the balance sheet, (b) the cost of properties not being amortized, if any, (c) the lower of cost or market value of unproved properties included in the cost being amortized, and (d) 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, a non-cash ceiling impairment is required.

As a result of its ceiling test, the Company recorded a non-cash impairment charge of $702.7 million in the year ended December 31, 2025. The Company did not have any ceiling test impairment charges for the years ended December 31, 2024 and 2023. Impairment charges affect the Company's reported net income but do not reduce the Company's cash flows.

Average commodity prices have declined in recent months. If this downward trend continues, and/or if our proved reserves decrease significantly in future months, the present value of the Company's future net revenues could decline significantly, which could trigger the need for the Company to record additional non-cash ceiling test impairment charges of its proved oil and gas property costs in future periods.

The Company computes the provision for depletion of oil and natural gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unproved costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are evaluated for reserves. The following table presents depletion and depletion per BOE sold of the Company's proved oil and natural gas properties for the periods presented:

	Year Ended December 31,		
(In thousands)	**2025**	**2024**	**2023**
Depletion of Proved Oil and Natural Gas Properties	$ 810,095	$ 736,600	$ 482,306
Depletion per BOE Produced	$ 16.43	$ 16.22	$ 13.37

The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

Capitalized costs associated with impaired unproved properties, which includes leases that have expired or have been deemed uneconomic, and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are included in the depletion calculation. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period. The costs of unproved properties are withheld from the depletion base until such time as they are evaluated for reserves. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the years ended December 31, 2025, 2024 and 2023, unproved properties of $7.8 million, $3.8 million, and $5.2 million, respectively, were impaired.

Asset Retirement Obligations

The Company records a liability equal to the fair value of the estimated cost to retire an asset upon initial recognition. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability. 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 added to the full cost pool and is subject to depletion. Upon settlement of the liability or the sale of the well, the liability is relieved. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements. Any variances between the liabilities recorded and the actual cost incurred to retire the assets is recorded as an adjustment to accumulated amortization of the full cost pool.

Business Combinations

The Company accounts for its acquisitions that qualify as a business using the acquisition method. Under the acquisition method, assets acquired and liabilities assumed are recognized and measured at their fair values. The use of fair value accounting requires the use of significant judgment since some transaction components do not have fair values that are readily determinable. The excess, if any, of the purchase price over the net fair value amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. Conversely, if the fair value of assets acquired exceeds the purchase price, including liabilities assumed, the excess is immediately recognized in earnings as a gain on bargain purchase.

Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, commodity derivative assets and liabilities, contingent consideration, and long-term debt. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the Company's derivative instruments assets and liabilities are based on a third-party industry-standard pricing model using contract terms and prices and assumptions and inputs that are substantially observable in active markets throughout the full term of the instruments, including forward oil price curves, discount rates, volatility factors and credit risk adjustments.

The carrying amount of long-term debt associated with borrowings outstanding under the Company's Revolving Credit Facility approximates fair value as borrowings bear interest at variable rates. The carrying amounts of the Company's Senior Notes and Convertible Notes (see Note 4 below) may not approximate fair value because carrying amounts are net of unamortized premiums and debt issuance costs, and the Senior Notes and Convertible Notes bear interest at fixed rates. See Note 11 for additional discussion.

Debt Issuance Costs

Debt issuance costs related to our Senior Notes and Convertible Notes are included as a deduction from the carrying amount of long-term debt in the balance sheets and are amortized to interest expense using the effective interest method over the term of the related debt. Debt issuance costs related to the Revolving Credit Facility are included in other noncurrent assets and are amortized to interest expense on a straight-line basis over the term of the credit agreement.

Debt Premiums and Discounts

Debt premiums and discounts related to the Company's Senior Notes are included as an addition to the carrying amount of the long-term debt in the balance sheets and are amortized to interest expense using the effective interest method over the term of the related notes.

Revenue Recognition

The Company's revenues are primarily derived from its interests in the sales of oil and natural gas production. The Company recognizes revenue from its interests in the sales of crude oil and natural gas in the period that its performance obligations are satisfied. Performance obligations are satisfied when the customer obtains control of the product, when the Company has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and natural gas are made under contracts which the third-party operators of the wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company receives payment from the sale of oil and natural gas production from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in accounts receivable, net in the balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received. Historically, differences have been insignificant. Accordingly, the variable consideration is not constrained.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient exemption, which applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company's oil is typically sold at delivery points under contract terms that are common in our industry. The Company's natural gas produced is delivered by the well operators to various purchasers at agreed upon delivery points under a limited number of contract types that are also common in our industry. Regardless of the contract type, the terms of these contracts compensate the well operators for the value of the oil and natural gas at specified prices, and then the well operators will remit payment to the Company for its share in the value of the oil and natural gas sold.

In June 2025, the Company entered into a settlement and mutual release agreement (the "Settlement Agreement") with an operator in North Dakota (the "Operator"). Pursuant to the Settlement Agreement, the Operator and the Company have settled and permanently released certain claims of the Company relating to certain post-production costs previously deducted from revenues. Pursuant to the settlement, the Company received approximately $81.7 million, recorded within Oil and Gas Sales in the accompanying statements of operations. The Company received a net cash settlement of $48.6 million after deducting approximately $33.1 million in legal settlement expenses.

The Company reports volumes and revenues on a two-stream basis. Accordingly, the Company's disaggregated revenue has two primary sources: (i) oil sales and (ii) natural gas and NGL sales. Substantially all of the Company's sales come from four operating areas in the United States: the Williston Basin, the Permian Basin, the Appalachian Basin, and the Uinta Basin.

The following tables presents the disaggregation of the Company's oil revenues and natural gas and NGL revenues for the years ended December 31, 2025, 2024 and 2023.

	Twelve Months Ended December 31,		
(In thousands)	**2025**	**2024**	**2023**
Oil Sales	$ 1,627,493	$ 1,897,857	$ 1,646,096
Natural Gas and NGL Sales[(1)]	453,795	254,222	251,683
Total	$ 2,081,288	$ 2,152,079	$ 1,897,779

(1) Balances for the year ended December 31, 2025 include $81.7 million in legal settlement from an Operator in North Dakota.

Concentrations of Market, Credit Risk and Other Risks

The future results of the Company's crude oil and natural gas operations will be affected by the market prices of crude oil and natural gas. The availability of a ready market for crude oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the crude oil and natural gas industry. The Company's receivables include amounts due, indirectly via the third-party operators of the wells, from purchasers of its crude oil and natural gas production. While certain of these customers, as well as third-party operators of the wells, are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations have been immaterial.

As a non-operator, 100% of the Company's wells are operated by third-party operating partners. As a result, the Company is highly dependent on the success of these third-party operators. If they are not successful in the exploration, development and production activities relating to the Company's leasehold interests, or are unable or unwilling to perform, the Company's financial condition and results of operations could be adversely affected. These risks are heightened in a low commodity price environment, which may present significant challenges to these third-party operators. The Company's third-party operators will make decisions in connection with their operations that may not be in the Company's best interests, and the Company may have little or no ability to exercise influence over the operational decisions of its third-party operators. For the years ended December 31, 2025, 2024 and 2023, the Company's top six operators made up 53%, 53% and 55%, respectively, of total oil and natural gas sales.

The Company faces concentration risk due to the fact that substantially all of its oil and natural gas revenue is sourced from a limited number of geographic areas of operations. As a result, the Company is disproportionately exposed to risks that affect one or more of those areas in the Williston Basin, the Permian Basin, the Appalachian Basin, and the Uinta Basin.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its counterparties is generally high. In the normal course of business, letters of credit or parent guarantees may be required for counterparties which management perceives to have a higher credit risk.

Reportable Segment Information

The Company has one reportable segment, which is engaged in the acquisition, exploration, development and production of crude oil and natural gas in the United States. All of the Company's oil and natural gas sales come from customers in the United States. The segment's revenues are primarily derived from our interests in the sales of crude oil and natural gas production. The Company's chief operating decision maker ("CODM") is our chief executive officer, who manages the Company's business activities as a single operating and reporting segment.

The accounting policies of the one reportable segment are the same as those described in the summary of significant accounting policies. The CODM uses net income, as reported in our statement of operations, to measure segment profit or loss, assess performance, and make strategic capital resources allocations. The measure of segment assets is reported on our balance sheet as total assets. The significant expense categories regularly provided to the CODM are the expenses as noted on the face of the statements of operations.

Stock-Based Compensation

The Company records expense associated with the fair value of stock-based compensation. For fully vested stock and restricted stock grants, the Company calculates the stock-based compensation expense based upon estimated fair value on the date of grant. In determining the fair value of performance-based share awards subject to market conditions, the Company utilizes a Monte Carlo simulation prepared by an independent third-party.

Treasury Stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result of share repurchases under the share repurchase program or from the withholding of shares of stock to satisfy employee tax withholding obligations that arise upon the lapse of restrictions on their stock-based awards at the employees' election.

Income Taxes

The Company's income tax expense, deferred tax assets and deferred tax liabilities reflect management's best assessment of estimated current and future taxes to be paid. The Company estimates for each interim reporting period the effective tax rate expected for the full fiscal year and uses that estimated rate in providing for income taxes on a current year-to-date basis. The Company's only taxing jurisdictions are the United States and the states in which we operate.

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements, which will result in taxable or deductible amounts in the future. In evaluating the Company's ability to recover its deferred tax assets, the Company considers all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax-planning strategies, and results of recent operations. In projecting future taxable income, the Company begins with historical results and incorporates assumptions about the amount of future state and federal pretax operating income adjusted for items that do not have tax consequences. The assumptions about future taxable income require significant judgment and are consistent with the plans and estimates the Company is using to manage its businesses.

Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is "more likely than not" that some components or all of the benefits of deferred tax assets will not be realized. As of December 31, 2025 and 2024, the Company recorded valuation allowances of $1.4 million and $1.8 million, respectively, against certain of the Company's deferred tax assets.

Derivative Instruments and Price Risk Management

The Company uses derivative instruments to manage market risks resulting from fluctuations in the prices of crude oil and natural gas commodities. The Company enters into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of the applicable commodity without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. The Company may also use exchange traded futures contracts and option contracts to hedge the delivery price of commodities at a future date.

The Company recognizes derivative instruments as assets or liabilities in the balance sheets, measured at fair value and marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net in the statements of operations. See Note 12 for a description of the open derivative contracts into which the Company has entered.

Employee Benefit Plans

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees upon hire. The plan allows eligible employees to make pre-tax contributions up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company offers matching contributions to its employees' retirement funds. Employees are 100% vested in the employer contributions upon receipt.

Net Income Per Common Share

Basic earnings per share ("EPS") are computed by dividing net income attributable to common stockholders (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include shares issuable upon exercise of stock warrants and vesting of restricted stock awards, and shares issuable upon conversion of the Convertible Notes (see Note 4). The number of potential common shares outstanding are calculated using the treasury stock or if-converted method.

In those reporting periods in which the Company has reported net income available to common stockholders, anti-dilutive shares generally are comprised of the restricted stock that has average unrecognized stock compensation expense greater than the average stock price. In those reporting periods in which the Company has a net loss, anti-dilutive shares are comprised of the impact of those number of shares that would have been dilutive had the Company had net income plus the number of common stock equivalents that would be anti-dilutive had the company had net income.

Restricted stock awards are excluded from the calculation of basic weighted average common shares outstanding until they vest. For restricted stock awards that vest based on achievement of performance and/or market conditions, the number of contingently issuable common shares included in diluted weighted-average common shares outstanding is based on the number of common shares, if any, that would be issuable under the terms of the arrangement if the performance and/or market conditions were met at the end of the reporting period, assuming the result would be dilutive.

Supplemental Cash Flow Information

The following table reflects the Company's supplemental cash flow information for the years ended December 31, 2025, 2024 and 2023:

	December 31,		
(In thousands)	**2025**	**2024**	**2023**
Supplemental Cash Items:			
Cash Paid During the Period for Interest, Net of Amount Capitalized	$ 170,862	$ 152,061	$ 128,943
Cash Paid (refund received) During the Period for Income Taxes, Net			
U.S. Federal	(1,484)	—	1,950
U.S. State and Local			
New Mexico	—	—	1,010
Pennsylvania	(383)	(26)	*
Texas	550	357	777
Utah	132	—	*
Other	13	1	89
Subtotal U.S. State and Local	312	332	1,876
Total Income Taxes Paid (Refunded), Net	(1,172)	332	3,826

*The amount of income taxes paid during the year ended December 31, 2023 does not meet the 5% disaggregation threshold.

Non-cash Investing Activities:			
Capital Expenditures on Oil and Natural Gas Properties Included in Accounts Payable and Accrued Liabilities	328,856	330,977	236,314
Capitalized Asset Retirement Obligations	5,456	8,028	5,413
Compensation Capitalized on Oil and Natural Gas Properties	934	786	280
Accrued Liabilities From Acquisitions of Oil and Natural Gas Properties	—	—	5,168
Issuance of Common Stock - Acquisitions of Oil and Natural Gas Properties	—	3,737	—
Non-cash Financing Activities:			
Common Stock Dividends Declared, but not paid	43,914	42,156	40,496
Issuance of Common Stock in Exchange for Warrants	—	23,338	13,328
Repurchases of Common Stock - Excise Tax, Net	258	944	—

Recently Adopted and Recently Issued Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("FASB") that are adopted by the Company as of the specified effective date, as applicable. If not discussed, management believes that the impact of recently issued accounting standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

Recently Adopted Accounting Pronouncements:

In December 2023, the FASB issued ASU 2023-09 Income Taxes (Topic 740): Improvements to Income Tax Disclosures, which requires the Company to disclose disaggregated jurisdictional and categorical information for the tax rate reconciliation, income taxes paid and other income tax related amounts. This guidance is effective for annual periods beginning after December 15, 2024, with early adoption permitted. The Company adopted ASU 2023-09 as of December 31, 2025, on a retrospective basis, with no significant impact on its financial statements. However, the adoption of ASU 2023-09 resulted in more detailed and enhanced footnote disclosures (see Note 2 and Note 10 to the financial statements).

Recently Issued Accounting Pronouncements:

In November 2024, the FASB issued ASU 2024-04 Debt - Debt With Conversion and Other Options (Subtopic 470-20): Induced Conversion of Convertible Debt Instruments. The objective of the standard is to improve the relevance and consistency in application of the induced conversion guidance in Subtopic 470-20, Debt with Conversion and Other Options. This standard will affect entities that settle convertible debt instruments for which the conversion privileges are changed to induce conversion. ASU 2024-04 is effective for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. The Company does not expect the adoption of this standard to have a material impact on its financial statements and related disclosures.

In November 2024, the FASB issued ASU 2024-03 Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard requires disclosure, in the notes to financial statements, of specified information about certain costs and expenses. The objective of the standard is to provide disaggregated information about a public business entity's expenses to help investors better understand the components of an entity's expenses, which should enable investors to better assess an entity's prospects for future cash flows. ASU 2024-03 is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The book value of the Company's crude oil and natural gas properties consists of all acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying statements of operations from the closing date of the acquisition. Acquired assets and liabilities assumed are recorded based on their estimated fair value at the time of the acquisition.

<u>2025 Acquisitions</u>

During 2025, the Company acquired oil and natural gas properties through a number of smaller independent transactions. Total expenditures for these properties, inclusive of acquisition and related development costs, were approximately $173.5 million.

In April 2025, the Company completed its acquisition of certain oil and natural gas properties, interests and related assets in the Midland Permian basin from a private seller, effective June 1, 2024. The total consideration paid to the seller at closing, net to the Company, was approximately $61.7 million in cash, a portion of which was funded by a $4.0 million acquisition deposit paid in February 2025.

In August 2025, the Company completed its acquisition of certain oil and natural gas properties, interests and related assets in the Uinta basin from a private seller, effective July 1, 2025. The total consideration paid to the seller at closing, net to the Company, was approximately $98.3 million in cash, a portion of which was funded by a $9.8 million acquisition deposit paid in June 2025.

Utica Acquisition

Subsequent to December 31, 2025, in February 2026, the Company completed its acquisition of certain upstream and midstream assets in the state of Ohio from Antero Resources Corporation and certain affiliated entities (collectively, "Antero"), effective as of July 1, 2025 (together, the "Utica Acquisition"). At closing, the Company acquired a 40% undivided working interest in the assets sold by Antero, with Infinity Natural Resources, LLC, an unaffiliated third party, acquiring the other 60% and becoming the operator of the acquired assets.

The total consideration paid to the seller at closing, net of customary purchase price adjustments, and net to the Company, was $464.6 million in cash, a portion of which was funded by a $58.8 million acquisition deposit paid in December 2025 and recorded in Other Noncurrent Assets, Net. In addition, the Company incurred approximately $5.5 million in transaction costs as a result of the Utica Acquisition. The Company has not yet completed its evaluation of its accounting methodology for the Utica Acquisition.

2024 Acquisitions

In addition to the closing of the Delaware Acquisition, the Point Acquisition and the XCL Acquisition (each as defined below), during 2024, the Company acquired oil and natural gas properties through a number of smaller independent transactions for a total of $53.1 million.

Delaware Acquisition

In January 2024, the Company completed its acquisition of certain oil and natural gas properties, interests and related assets in the Delaware Basin from a private seller, effective as of November 1, 2023 (the "Delaware Acquisition").

The total consideration paid to the seller at closing included 107,657 shares of common stock and $147.8 million in cash, a portion of which was funded by a $17.1 million deposit paid at signing in November 2023.

The results of operations from the date of the Delaware Acquisition through December 31, 2024 represented approximately $43.4 million of revenue and $17.6 million of income from operations.

The Company accounted for the Delaware Acquisition as a business combination. Accordingly, transaction costs of approximately $0.6 million were included in general and administrative expense in the Company's statements of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	151,912
Total assets acquired		151,912
Asset retirement obligations		(380)
Net assets acquired	$	151,531
Fair value of consideration paid for net assets:		
Cash consideration	$	147,794
Non-cash consideration	$	3,737
Total fair value of consideration transferred	$	151,531

Point Acquisition

In September 2024, the Company completed its acquisition of certain oil and natural gas properties located in the Delaware Basin from Point Energy Partners, LLC ("Point"), effective as of April 1, 2024 (the "Point Acquisition"). At closing, the Company acquired a 20% undivided working interest in the assets sold by Point, with Vital Energy, Inc., an unaffiliated third party, acquiring the other 80% and becoming the operator of the acquired assets.

The total consideration paid to the seller at closing, net to the Company, was $205.1 million in cash, a portion of which was funded by a $22.0 million acquisition deposit paid in July 2024. As a result of customary post-closing adjustments, the Company reduced its proved oil and natural gas properties and total consideration by $7.2 million subsequent to closing.

The Company accounted for the Point Acquisition as an asset acquisition, as substantially all of the fair value of the gross assets acquired were concentrated in a group of similar identifiable assets. Accordingly, approximately $2.8 million transaction costs were capitalized to the full cost pool of the oil and natural gas properties acquired.

XCL Acquisition

In October 2024, the Company completed its acquisition of certain oil and natural gas properties in the Uinta Basin from XCL Resources, LLC and certain affiliated entities ("XCL"), effective as of May 1, 2024 (the "XCL Acquisition"). At closing, the Company acquired a 20% undivided working interest in the assets sold by XCL, with SM Energy Company, an unaffiliated third party, acquiring the other 80% and becoming the operator of the acquired assets.

The total consideration paid to the seller at closing, net to the Company, was $511.3 million in cash, a portion of which was funded by a $25.5 million acquisition deposit paid in June 2024.

The Company accounted for the XCL Acquisition as an asset acquisition, as substantially all of the fair value of the gross assets acquired were concentrated in a group of similar identifiable assets. Accordingly, approximately $9.4 million transaction costs were capitalized to the full cost pool of the oil and natural gas properties acquired.

Divestitures

From time-to-time the Company may divest assets. In addition, the Company may trade leasehold interests with operators to balance working interests in spacing units to facilitate and encourage a more expedited development of the Company's acreage.

Unproved Properties

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion until the properties are evaluated for reserves. Once a property is evaluated, all associated acreage and drilling costs are subject to depletion.

Unproved properties not being amortized comprise approximately 20,208 net acres and 45,388 net acres of undeveloped leasehold interests at December 31, 2025 and 2024, respectively. The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other unproved properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired and transferred into the full cost pool. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2025 by year incurred.

	December 31,			
(In thousands)	**2025**	**2024**	**2023**	**Prior Years**
Property Acquisition	$ 62,332	$ 17,661	$ 802	$ 5,239
Total	$ 62,332	$ 17,661	$ 802	$ 5,239

The Company historically has acquired unproved properties by purchasing individual or small groups of leases directly from mineral owners, landmen or lease brokers, which leases historically have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. The Company generally participates in drilling activities on a heads up basis by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling.

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

NOTE 4 LONG-TERM DEBT

The Company's long-term debt consists of the following:

	December 31, 2025			
(In thousands)	Principal Balance	Premium/ (Discount)	Debt Issuance Costs, Net	Long-term Debt, Net
Revolving Credit Facility [1]	$ 478,000	$ —	$ —	$ 478,000
Senior Notes due 2028	20,165	124	(139)	20,150
Convertible Notes due 2029	700,000	9,619	(15,125)	694,494
Senior Notes due 2031	500,000	(4,828)	(6,399)	488,773
Senior Notes due 2033	725,000	—	(11,024)	713,976
Total	$ 2,423,165	$ 4,915	$ (32,687)	$ 2,395,393

	December 31, 2024			
	Principal Balance	Premium/ (Discount)	Debt Issuance Costs, Net	Long-term Debt, Net
Revolving Credit Facility [1]	690,000	—	—	690,000
Senior Notes due 2028	705,108	6,346	(7,097)	704,357
Convertible Notes due 2029	500,000	—	(11,780)	488,220
Senior Notes due 2031	500,000	(5,712)	(7,571)	486,717
Total	$ 2,395,108	$ 634	$ (26,448)	$ 2,369,294

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(1) Unamortized debt issuance costs related to the Company's Revolving Credit Facility of 13.1 million and $9.0 million as of December 31, 2025 and 2024, are recorded in "Other Noncurrent Assets, Net" in the balance sheets.

Revolving Credit Facility

In November 2025, the Company entered into a Fourth Amended and Restated Credit Agreement (the "Revolving Credit Facility") with Wells Fargo Bank, National Association, as administrative agent and collateral agent ("Agent"), and the lenders from time to time party thereto, which amended and restated the Company's prior revolving credit facility that was entered into in June 2022. The Revolving Credit Facility matures on November 5, 2030.

The Revolving Credit Facility is comprised of revolving loans and letters of credit and is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to the Company and its subsidiaries' (if any) oil and natural gas properties. The Company's borrowing availability under the Revolving Credit Facility is set at the lesser of the borrowing base and the elected commitment amount. The borrowing base will be redetermined semiannually on or around April 1 and October 1, with one interim "wildcard" redetermination available to each of the Company and the Agent (acting at the direction of the lenders holding at least two-thirds of commitments and loans outstanding under the Revolving Credit Facility) between scheduled redeterminations. Upon an acquisition of oil and natural gas properties with an aggregate value exceeding 5% of the borrowing base, the Company may request an additional redetermination.

Subsequent to December 31, 2025, in February 2026, the Company completed a wildcard redetermination. In connection therewith, the borrowing base was increased from $1.8 billion to $1.975 billion, and the aggregate elected commitment amount was increased from $1.6 billion to $1.8 billion.

The Company has the option to seek commitments for term loans, which such term loans (if obtained), together with any other then-outstanding principal amount of term loans, are capped at the least of (i) the borrowing base minus the aggregate elected commitment amount, (ii) the aggregate elected commitment amount and (iii) one-third of the sum of (x) the aggregate elected commitment amount plus (y) the then-outstanding principal amount of term loans plus (z) the term loans being established on a pro forma basis. Such term loans are subject to certain other terms of the Revolving Credit Facility.

At the Company's option, borrowings under the Revolving Credit Facility shall bear interest at the base rate or SOFR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the Agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 75 to 175 basis points, and the applicable margin for SOFR loans ranges from 175 to 275 basis points, in each case depending on the percentage of the borrowing base utilized.

The Revolving Credit Facility contains customary events of default and affirmative and negative covenants. In addition, the Revolving Credit Facility requires that the Company comply with the following financial covenants: (i) the Net Leverage Ratio (as defined in the Revolving Credit Facility) shall be no more than 3.50 to 1.00, and (ii) the Current Ratio (as defined in the Revolving Credit Facility) shall not be less than 1.00 to 1.00. The Company was in compliance with all applicable covenants as of December 31, 2025.

The Company's obligations under the Revolving Credit Facility are secured by mortgages on not less than 85% of the value of proven reserves associated with the oil and natural gas properties included in the determination of the borrowing base. Additionally, the Company entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which the Company's obligations under the Revolving Credit Facility are secured by a first priority security interest in substantially all of the Company's assets.

<u>Senior Notes due 2028</u>

In February 2021, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "2028 Notes Indenture"), pursuant to which the Company issued $550.0 million in aggregate principal amount of 8.125% senior notes due 2028 (the "Original 2028 Notes"). In November 2021, the Company issued an additional $200.0 million aggregate principal amount of 8.125% senior notes due 2028 (together with the Original 2028 Notes, the "Senior Notes due 2028"). The proceeds of the Senior Notes due 2028 were used primarily to refinance existing indebtedness, and for general corporate purposes.

During 2022, the Company repurchased and retired $25.8 million in aggregate principal amount of the Senior Notes due 2028 in open market transactions for a total of $24.9 million in cash, plus accrued interest. During 2023, the Company repurchased and retired $19.1 million in aggregate principal amount of the Senior Notes due 2028 in open market transactions for a total of $18.4 million in cash, plus accrued interest.

In October 2025, upon successfully completing the issuance of its Senior Notes due 2033, the Company repurchased approximately 97.14% of its outstanding Senior Notes due 2028, representing approximately $684.9 million in aggregate principal amount, for a total amount of $699.9 million, inclusive of tender premium and accrued interest due (the "Repurchase Event"). The Repurchase Event resulted in a loss on debt extinguishment of approximately $10.8 million, primarily due to the tender premium of $10.3 million paid in conjunction with the cash tender offer to holders of the Senior Notes due 2028 upon the Repurchase Event. As of December 31, 2025, the Company's liability under the 2028 Notes Indenture was approximately $20.2 million.

The Senior Notes due 2028 will mature on March 1, 2028. Interest is payable semi-annually in arrears on each March 1 and September 1 to holders of record on the February 15 and August 15 immediately preceding the related interest payment date, at a rate of 8.125% per annum. The Company may redeem all or a part of the outstanding Senior Notes due 2028 at redemption prices (expressed as percentages of principal amount) equal to 102.031% through February 28, 2026, and 100% beginning on March 1, 2026, plus accrued and unpaid interest to, but excluding, the redemption date.

Subsequent to December 31, 2025, in February 2026, the Company gave notice to the holders of the Senior Notes due 2028 (the "Notice of Full Redemption") that it elected to redeem all of the outstanding Senior Notes due 2028, in accordance with the terms of the 2028 Notes Indenture. Pursuant to the Notice of Full Redemption, the Redemption Date is March 4, 2026, and the Redemption Price is 100%.

If a Change of Control Triggering Event (as defined in the 2028 Notes Indenture) occurs, each holder of Senior Notes due 2028 may require the Company to repurchase all or any part of that holder's Senior Notes due 2028 for cash at a price equal to 101% of the aggregate principal amount of the Senior Notes due 2028 repurchased, plus any accrued and unpaid interest on the Senior Notes due 2028 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2028 Notes Indenture contains customary events of default and affirmative and negative covenants. As of December 31, 2025, the Company was in compliance with all applicable covenants.

Convertible Notes due 2029

In October 2022, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (as supplemented, the “Convertible Notes Indenture”), pursuant to which the Company issued $500.0 million in aggregate principal amount of 3.625% convertible senior notes due 2029 (the “ Original Convertible Notes”). In June 2025, the Company issued an additional $200.0 million in aggregate principal amount of 3.625% convertible senior notes due 2029 (the “Additional Convertible Notes” and, together with the Original Convertible Notes, the “Convertible Notes”), at an issue price of 105.597% of the principal amount thereof. The proceeds of the Convertible Notes were used to refinance existing indebtedness and for other general corporate purposes. The Convertible Notes mature on April 15, 2029, unless earlier repurchased, redeemed or converted. The Convertible Notes accrue interest at a rate of 3.625% per annum, payable semi-annually in arrears on April 15 and October 15 of each year.

Before October 16, 2028, noteholders have the right to convert their Convertible Notes only upon the occurrence of certain events. From and after October 16, 2028, noteholders may convert their Convertible Notes at any time at their election until the close of business on the second scheduled trading day immediately before the maturity date. The Company will have the right to elect to settle conversions either entirely in cash or in a combination of cash and shares of its common stock. However, upon conversion of any Convertible Notes, the conversion value, which will be determined over a period of 40 trading days, will be paid in cash up to at least the principal amount of the Convertible Notes being converted. The conversion rate and conversion price are subject to customary anti-dilution and other adjustments upon the occurrence of certain events. As of December 31, 2025, the conversion rate was 27.4611 shares of common stock per $1,000 principal amount of Convertible Notes, which represented a conversion price of approximately $36.42 per share of common stock. In addition, if certain corporate events that constitute a “Make-Whole Fundamental Change” (as defined in the Convertible Notes Indenture) occur, then the conversion rate will, in certain circumstances, be increased for a specified period of time.

The Convertible Notes are redeemable, in whole or in part (subject to certain limitations), at the Company’s option at any time, and from time to time, on or after April 15, 2026 and on or before the 40th scheduled trading day immediately before the maturity date, at a cash redemption price equal to the principal amount of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date, but only if the last reported sale price per share of the Company’s common stock exceeds 130% of the conversion price on (i) each of at least 20 trading days, whether or not consecutive, during the 30 consecutive trading days ending on, and including, the trading day immediately before the date the Company sends the related redemption notice; and (ii) the trading day immediately before the date the Company sends such notice. In addition, calling any Convertible Note for redemption will constitute a Make-Whole Fundamental Change with respect to that Convertible Note, in which case the conversion rate applicable to the conversion of that Convertible Note will be increased in certain circumstances if it is converted after it is called for redemption. Notwithstanding the foregoing, the Company has agreed not to call any Additional Convertible Notes for redemption until the Additional Convertible Notes are “freely tradeable” (as defined in the Convertible Notes Indenture) pursuant to the provision to the first sentence of the definition thereof.

If certain corporate events that constitute a “Fundamental Change” (as defined in the Convertible Notes Indenture) occur, then, subject to a limited exception for certain cash mergers, noteholders may require the Company to repurchase their Convertible Notes at a cash repurchase price equal to the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest, if any, to, but excluding, the fundamental change repurchase date. The definition of Fundamental Change includes certain business combination transactions involving the Company and certain de-listing events with respect to the Company’s common stock.

The Convertible Notes Indenture contains customary events of default and affirmative and negative covenants. As of December 31, 2025, the Company was in compliance with all applicable covenants.

Capped Call Transactions

In October 2022, in connection with the Original Convertible Notes offering described above, the Company entered into privately negotiated capped call transactions (the “Original Capped Call Transactions”) with certain of the initial purchasers of the Original Convertible Notes and/or their respective affiliates and/or other financial institutions. The Company paid $36.1 million in total consideration to enter into the Original Capped Call Transactions. The Original Capped Call Transactions cover, subject to anti-dilution adjustments substantially similar to those applicable to the conversion rate of the Convertible Notes, the number of shares of common stock initially underlying the Original Convertible Notes. The Original Capped Call Transactions are expected generally to reduce potential dilution to the common stock upon any conversion of Original Convertible Notes and/or offset any potential cash payments the Company is required to make in excess of the principal amount of such converted Original Convertible Notes, as the case may be, with such reduction and/or offset subject to a cap. The cap price of the Original Capped Call Transactions was initially approximately $52.17 per share of common stock, which represents a premium of 75% over the last reported sale price of the common stock of $29.81 per share on October 11, 2022, and is subject to certain customary adjustments under the terms of the Original Capped Call Transactions.

In June 2025, in connection with the Additional Convertible Notes offering described above, the Company entered into new privately negotiated capped call transactions (the "Additional Capped Call Transactions"). The Additional Capped Call Transactions cover, subject to anti-dilution adjustments substantially similar to those applicable to the conversion rate of the Convertible Notes, the number of shares of common stock initially underlying the Additional Convertible Notes. The Additional Capped Call Transactions are expected generally to reduce potential dilution to the common stock upon any conversion of Additional Convertible Notes and/or offset any cash payments the Company is required to make in excess of the principal amount of such converted Additional Convertible Notes, as the case may be, with such reduction and/or offset subject to a cap. The cap price of the Additional Capped Call Transactions was initially approximately $50.61 per share of common stock, which represents a premium of approximately 63% over the last reported sale price of the common stock of $31.15 per share on June 12, 2025, and is subject to certain customary adjustments under the terms of the Additional Capped Call Transactions.

As of December 31, 2025, the cap price of the Capped Call Transactions was approximately $49.98 per share of common stock for both the Original Capped Call Transactions and the Additional Capped Call Transactions.

Senior Notes due 2031

In May 2023, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "2031 Notes Indenture"), pursuant to which the Company issued $500.0 million in aggregate principal amount of the Company's 8.750% senior notes due 2031 (the "Senior Notes due 2031"). The proceeds of the Senior Notes due 2031 were used primarily to refinance existing indebtedness, and for general corporate purposes.

The Senior Notes due 2031 will mature on June 15, 2031. Interest is payable semi-annually in arrears on each June 15 and December 15, to holders of record on the June 1 and December 1 immediately preceding the related interest payment date, at a rate of 8.750% per annum. Prior to June 15, 2026, the Company may redeem up to 35% of the aggregate principal amount of Senior Notes due 2031, upon not less than 10 or more than 60 days' notice, at a redemption price of 108.750% of the principal amount of the Senior Notes due 2031 redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date), in an amount not greater than the net cash proceeds of one or more equity offerings by the Company, provided that (i) at least 65% of the aggregate principal amount of Senior Notes due 2031 issued under the 2031 Notes Indenture (including any Additional Notes (as defined in the 2031 Notes Indenture) but excluding the Senior Notes due 2031 held by the Company and its Subsidiaries (as defined in the 2031 Notes Indenture)) remains outstanding immediately after the occurrence of such redemption (unless all Senior Notes due 2031 are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days of the date of the closing of each such equity offering. In addition, prior to June 15, 2026, the Company may redeem all or a part of the Senior Notes due 2031, on any one or more occasions, upon not less than 10 or more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Senior Notes due 2031 redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date).

On or after June 15, 2026, the Company may redeem all or a part of the Senior Notes due 2031 at redemption prices (expressed as percentages of principal amount) equal to 104.375% for the twelve-month period beginning on June 15, 2026, 102.188% for the twelve-month period beginning on June 15, 2027, and 100% beginning on June 15, 2028, plus accrued and unpaid interest to, but excluding, the redemption date.

If a Change of Control Triggering Event (as defined in the 2031 Notes Indenture) occurs, each holder of Senior Notes due 2031 may require the Company to repurchase all or any part of that holder's Senior Notes due 2031 for cash at a price equal to 101% of the aggregate principal amount of the Senior Notes due 2031 repurchased, plus any accrued and unpaid interest on the Senior Notes due 2031 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2031 Notes Indenture contains customary event of default and certain affirmative and negative covenants. As of December 31, 2025, the Company was in compliance with all applicable covenants.

Senior Notes due 2033

In October 2025, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "2033 Notes Indenture"), pursuant to which the Company issued $725.0 million in aggregate principal amount of the Company's 7.875% senior notes due 2033 (the "Senior Notes due 2033"). The proceeds of the Senior Notes due 2033 were used primarily to fund the purchase of the Senior Notes due 2028 validly tendered and accepted for purchase pursuant to the Tender Offer, and for general corporate purposes.

The Senior Notes due 2033 will mature on October 15, 2033. Interest is payable semi-annually in arrears on each April 15 and October 15, to holders of record on the April 1 and October 1 immediately preceding the related interest payment date, at a rate of 7.875% per annum. Prior to October 15, 2028, the Company may redeem up to 40% of the aggregate principal amount of Senior Notes due 2033, upon not less than 10 or more than 60 days' notice, at a redemption price of 107.875% of the principal amount of the Senior Notes due 2033 redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date), in an amount not greater than the net cash proceeds of one or more equity offerings by the Company, provided that (i) at least 60% of the aggregate principal amount of Senior Notes due 2033 issued under the 2033 Notes Indenture (including any Additional Notes (as defined in the 2033 Notes Indenture) but excluding the Senior Notes due 2033 held by the Company and its Subsidiaries (as defined in the 2033 Notes Indenture)) remains outstanding immediately after the occurrence of such redemption (unless all Senior Notes due 2033 are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days of the date of the closing of each such equity offering. In addition, prior to October 15, 2028, the Company may redeem all or a part of the Senior Notes due 2033, on any one or more occasions, upon not less than 10 or more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Senior Notes due 2033 redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date).

On or after October 15, 2028 the Company may redeem all or a part of the Senior Notes due 2033 at redemption prices (expressed as percentages of principal amount) equal to 103.938% for the twelve-month period beginning on October 15, 2028, 101.969% for the twelve-month period beginning on October 15, 2029, and 100% beginning on October 15, 2030, plus accrued and unpaid interest to, but excluding, the redemption date.

If a Change of Control Triggering Event (as defined in the 2033 Notes Indenture) occurs, each holder of Senior Notes due 2033 may require the Company to repurchase all or any part of that holder's Senior Notes due 2033 for cash at a price equal to 101% of the aggregate principal amount of the Senior Notes due 2033 repurchased, plus any accrued and unpaid interest on the Senior Notes due 2033 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2033 Notes Indenture contains customary event of default and certain affirmative and negative covenants. As of December 31, 2025, the Company was in compliance with all applicable covenants.

NOTE 5 COMMON AND PREFERRED STOCK

Common Stock

On May 23, 2024, the Company filed an amendment to its certificate of incorporation, which was effective upon filing, to increase the number of authorized shares of common stock, par value $0.001 per share, from 135,000,000 to 270,000,000, as approved by the Company's stockholders at the 2024 Annual Meeting of Stockholders on May 23, 2024. As of December 31, 2025 and 2024, the Company had 97,265,559 and 99,113,645 shares of common stock issued and outstanding, respectively.

Preferred Stock

The Company is authorized to issue up to 5,000,000 shares of preferred stock, par value $0.001 per share, with such designations, voting and other rights and preferences as may be determined from time to time by the Company's board of directors. As of December 31, 2025 and 2024, the Company had zero shares of preferred stock issued and outstanding.

2025 Activity

Common Stock

During the year ended December 31, 2025, 80,247 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with the vesting of their restricted stock awards. The total value of these shares surrendered, based on the market prices on the dates the shares were surrendered, was approximately $2.1 million.

During the year ended December 31, 2025, 9,246 shares of the Company's stock, previously issued as stock-based compensation, were forfeited by former employees of the Company upon separation.

During the year ended December 31, 2025, the Company issued 190,403 shares of its common stock to executive officers, employees, and directors as stock-based compensation (see Note 6).

Dividends

In January 2025, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend was paid on April 30, 2025, to stockholders of record as of the close of business on March 28, 2025.

In April 2025, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend was paid on July 31, 2025, to stockholders of record as of the close of business on June 27, 2025.

In July 2025, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend was paid on October 31, 2025, to stockholders of record as of the close of business on September 29, 2025.

In November 2025, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend was paid on January 30, 2026, to stockholders of record as of the close of business on December 30, 2025.

Subsequent to December 31, 2025, in February 2026, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend is payable on April 30, 2026, to stockholders on record as of the close of business on March 30, 2026.

Stock Repurchase Program

In May 2022, the Company's board of directors approved a stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. In July 2024, the Company's board of directors terminated the prior stock repurchase program, which was substantially depleted, and approved a new stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. In March 2025, the Company' s board of directors approved a $100.0 million increase to the authorization under this stock repurchase program. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market in block transactions and in negotiated transactions.

During the year ended December 31, 2025, the Company repurchased 1,948,996 shares of its common stock for $57.3 million (including commissions and $0.3 million in excise tax) under the stock repurchase program. During the year ended December 31, 2024, the Company repurchased 2,535,391 shares of its common stock for $95.4 million (including commissions and $0.9 million in excise tax) under the stock repurchase program.

The Company's accounting policy upon the repurchase of shares is to deduct its par value from common stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital. All repurchased shares are included in the Company's pool of authorized but unissued shares.

NOTE 6 STOCK-BASED COMPENSATION AND WARRANTS

Stock-Based Compensation

The Company maintains the Amended and Restated 2018 Equity Incentive Plan (the "2018 Plan") for the purpose of making equity-based awards to employees, directors and other eligible persons. As of December 31, 2025, there were 2,598,210 shares available for future awards or settlement of awards under the 2018 Plan.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and are included in the "General and administrative expenses" line item in the statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Oil and natural gas properties" line item in the balance sheets.

Issuances made pursuant to the 2018 Plan are summarized as follows:

The Company issues share-based awards in the form of restricted stock awards ("RSAs"), restricted stock units ("RSUs") and share appreciation awards ("SARs"), subject to various vesting conditions, as compensation to executive officers, employees and directors of the Company. Typically, RSAs issued to employees and executive officers contain a service condition only and generally vest over three or four years. Typically, RSUs and SARs contain both a service and market condition. Market conditions can be the Company's absolute total shareholder return ("TSR"), the Company's TSR ranking among its peer companies or the Company's market capitalization growth measured over a defined performance period. Grantees' continued employment through the end of the performance period is required for such RSUs and SARs to vest. RSAs issued to directors generally vest either immediately or over one year, subject to continued service and provided that any performance and/or market conditions are also met.

For awards subject to service and/or performance vesting conditions, the grant date fair value is established based on the closing price of the Company's common stock on such date. Stock-based compensation expense for awards subject to only service conditions is recognized on a straight-line basis over the service period. Stock-based compensation expense for awards subject to both service and performance conditions are recognized on a graded basis if it is probable that the performance condition will be achieved. The Company accounts for forfeitures of awards granted under these plans as they occur in determining stock-based compensation expense.

For awards subject to a market condition, the grant date fair value is estimated using a Monte Carlo valuation model. The Company recognizes stock-based compensation expense for awards subject to market-based vesting conditions regardless of whether the market conditions are achieved or not, and stock-based compensation expense for any such awards is reversed only when the implied service requirement is not met. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility and implied volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period.

Service-Based RSAs

During 2025, 2024 and 2023, the Company granted 190,403, 225,773 and 468,268 shares, respectively, of service-based RSAs to executive officers, employees and directors under the 2018 Equity Plan. The weighted average grant date fair value of service-based RSAs was $26.98 per share, $36.15 per share and $35.19 per share for the years ended December 31, 2025, 2024, and 2023, respectively.

The following table reflects the outstanding service-based RSAs and activity related thereto for the year ended December 31, 2025:

	Service-based Awards	
	Number of Shares	Weighted-average Grant Date Fair Value
Outstanding at December 31, 2024	457,376	$ 35.36
Shares granted	190,403	26.98
Shares forfeited	(9,246)	31.92
Shares vested	(236,193)	31.80
Outstanding at December 31, 2025	402,340	$ 33.58

At December 31, 2025, there was $8.9 million of total unrecognized compensation expense related to unvested RSAs. That cost is expected to be recognized over a weighted average period of 1.0 year. For the years ended December 31, 2025, 2024 and 2023, the total fair value of the Company's restricted stock awards vested was $6.3 million, $8.0 million and $6.2 million, respectively. For the years ended December 31, 2025, 2024 and 2023, the compensation expenses associated with these awards were $8.0 million, $7.5 million and $6.0 million respectively.

Performance Equity Awards

The following table reflects the outstanding RSUs that are subject to market conditions linked to TSR ("TSR Awards") and activity related thereto for the year ended December 31, 2025:

	TSR Awards	
	Number of Units	Weighted-average Grant Date Fair Value
Outstanding at December 31, 2024	287,990	$ 38.87
Units granted	223,929	21.78
Outstanding at December 31, 2025	511,919	$ 31.40

For the years ended December 31, 2025, 2024 and 2023, the compensation expenses associated with these awards were $6.1 million, $3.0 million, and $0.0 million, respectively. As of December 31, 2025, the unrecognized compensation expenses for these awards were $6.9 million, which will be amortized over the remaining performance period.

In December 2023, the Company also granted performance equity awards, in the form of SARs. The final payout (if any) will be a dollar amount, which may be settled in cash, shares or a combination of both at the Company's option. The Company plans to settle the SARs Awards that were granted in 2023 with shares. For the years ended December 31, 2025 and 2024, the compensation expenses associated with these awards were $1.5 million and $1.5 million. As of December 31, 2025, the unrecognized compensation expenses for these awards were $3.0 million, which will be amortized over the remaining performance period.

The Company used Monte Carlo simulation models, described above, to estimate (i) the fair value of the TSR Awards that were granted in 2023 and 2024 based on the expected outcome of the Company's absolute TSR as well as TSR relative to the defined peer group and (ii) the fair value of the SARs that were granted in 2023 based on the expected outcome of the Company's market capitalization appreciation rate. The Company used the following key assumptions in its Monte Carlo simulation models: (a) risk-free rates ranging from 1.7% to 4.2%, (b) dividend yield ranging from nil to 4.3%, and (c) expected volatility ranging from 56.4% to 72.3%.

Warrants

In January 2022, as partial consideration for the purchase of certain oil and natural gas properties, the Company issued warrants to purchase 1,939,998 shares of the Company's common stock at an exercise price equal to $28.30 per share (subject to certain anti-dilution adjustments) (the "Warrants").

In March 2023, the Company issued 403,780 shares of common stock in exchange for the surrender and cancellation of a portion of the Warrants. Immediately prior to their cancellation, such Warrants that were surrendered were exercisable for an aggregate of approximately 824,602 shares of common stock at an exercise price of $27.4946 per share. Neither the Company nor the holders paid any cash consideration in the transaction.

In March 2024, the Company issued 656,297 shares of common stock in exchange for the surrender and cancellation of all of the remaining Warrants. Immediately prior to their cancellation, such Warrants that were surrendered were exercisable for an aggregate of approximately 1,223,963 shares of common stock at an exercise price of $26.3324 per share. Neither the Company nor the holders paid any cash consideration in the transaction.

There were no outstanding warrants or activity related thereto for the year ended December 31, 2025.

NOTE 7 RELATED PARTY TRANSACTIONS

There were no material related party transactions as of December 31, 2025. The Company's Audit Committee is responsible for approving all transactions involving related parties.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in various proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including, but not limited to, court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company's opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the Company's financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

NOTE 9 ASSET RETIREMENT OBLIGATIONS

The Company has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Initially, the fair value of a liability for an asset retirement obligation ("ARO") is recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is included in the full cost pool, subject to depletion. If the liability is settled for an amount other than the recorded amount, an adjustment to the full cost pool is recognized. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted risk-free discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO, a corresponding adjustment is made to the oil and gas property balance. For example, as the Company analyzes actual plugging and abandonment information, the Company may revise its estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of its wells.

The following table summarizes the Company's asset retirement obligation transactions recorded during the years ended December 31, 2025 and 2024.

	December 31,	
(in thousands)	**2025**	**2024**
Beginning Asset Retirement Obligations	$ 49,197	$ 39,889
Liabilities Incurred During the Period	5,456	8,342
Revision of Estimates	8	3,672
Accretion of Discount on Asset Retirement Obligations	3,303	2,852
Liabilities Settled During the Period	(4,237)	(5,558)
Ending Asset Retirement Obligations	$ 53,727	$ 49,197

The table below sets forth the short term and long term asset retirement obligation balances as of the years ended December 31, 2025 and 2024.

	December 31,	
(in thousands)	2025	2024
Asset Retirement Obligations - Current Liabilities	$ 2,896	$ 3,290
Asset Retirement Obligations - Noncurrent Liabilities	50,831	45,907
Ending Asset Retirement Obligations	$ 53,727	$ 49,197

The short term asset retirement obligation balance is reported in Other Current Liabilities in the Company's balance sheets.

NOTE 10 INCOME TAXES

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income (loss) in the period that includes the enactment date.

The One Big Beautiful Bill, which was enacted in July 2025, primarily makes permanent the tax implications of the Tax Cuts and Jobs Act from 2017. The income tax provisions include the reinstatement of the 100% additional first-year "bonus" depreciation deduction, updates to the calculation of disallowed interest, and updates to the determination of whether the Company is subject to the Corporate Alternative Minimum Tax.

The income tax provisions for the years ended December 31, 2025, 2024, and 2023 consist of the following:

(In thousands)	2025	2024	2023
Current			
Federal	$ —	$ —	$ —
State	374	959	915
Total Current Tax Expense (Benefit)	$ 374	$ 959	$ 915
Deferred			
Federal	16,435	145,224	209,168
State	7,499	14,402	22,035
Valuation Allowance	(364)	(76)	(154,345)
Total Deferred Tax Expense (Benefit)	$ 23,570	$ 159,550	$ 76,858
Total Tax Expense	$ 23,944	$ 160,509	$ 77,773

The following is a reconciliation of the reported amount of income tax expense for the years ended December 31, 2025, 2024, and 2023 to the amount of income tax expenses that would result from applying the statutory rate to pretax income.

(In thousands)	2025		2024		2023	
Income Before Income Taxes	$ 62,705		$ 680,817		$1,000,742	
Tax Provision at the U.S. Federal Statutory Rate	13,168	21.0 %	143,026	21.0 %	210,156	21.0 %
State Income Taxes, Net of Federal Income Tax Benefit [(1)]	7,400	11.8 %	15,027	2.2 %	(3,382)	(0.3)%
Nontaxable and Nondeductible Items:						
Nondeductible Compensation	1,218	1.9 %	1,638	0.2 %	1,175	0.1 %
Reclassification of Productions Taxes [(2)]	—	— %	(3,123)	(0.5)%	—	— %
Federal True-Up Adjustments	3	— %	3,108	0.5 %	(1,532)	(0.2)%
Other Nontaxable or Nondeductible Items	2,155	3.4 %	834	0.1 %	(455)	— %
Change in Valuation Allowance [(3)]	—	— %	—	— %	(128,189)	(12.8)%
Reported Tax Expense	$ 23,944	38.2 %	$ 160,509	23.6 %	$ 77,773	7.8 %

(1) The jurisdictions that make up the majority of the state income taxes are North Dakota, New Mexico and Texas, inclusive of changes in valuation allowances ($26M release in 2023).

(2) Refer to Note 2 Out-of-Period Adjustments in the 2024 Form 10-K.

(3) The valuation allowance balances presented are only for federal taxes. Valuation allowances for state taxes are netted with the state tax items.

Acquisitions, divestitures, and the prices received for crude oil, natural gas and NGL impact the apportionment of taxable income to the states where we own crude oil and natural gas properties. As these factors change, our state income tax rate changes. This change, when applied to our total temporary differences, impacts the total state income tax expense or benefit reported in the current year.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. During 2025, in evaluating whether it was more likely than not that the Company’s net deferred tax assets were realized through future net income, management considered all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the projected future income and results of operations, and (iv) its ability to use tax planning strategies. Based on all the evidence available, at December 31, 2025 and December 31, 2024 the Company recorded valuation allowances of $1.4 million and $1.8 million, respectively.

At December 31, 2025, the Company had a NOL carryforward for federal income tax purposes of $532.8 million, of which $121.7 million are limited by IRC Section 382, and gross state NOL carryforwards of $690.5 million. The determination of the state NOL carryforwards is dependent upon apportionment percentages, state income tax rates, and state laws that can change from year to year and that can thereby impact the amount of the deferred tax asset related to such carryforwards. Our $121.7 million IRC Section 382 limited federal NOLs expire in 2037, and the remaining $411.0 million of federal NOLs have an indefinite life. If unutilized, all of the state net operating losses will expire from 2025 to 2045, except for $194.9 million of state net operating losses that have an indefinite life.

The significant components of the Company's deferred tax assets (liabilities) were as follows:

(in thousands)	Year Ended December 31, 2025	2024
NOLs and Tax Credit Carryforwards	$ 136,682	$ 117,035
Share Based Compensation	358	477
Accrued Interest	1,022	1,005
Crude Oil and Natural Gas Properties and Other Properties	(412,647)	(434,486)
Interest Carryforwards	47,118	68,926
Derivative Instruments	(28,647)	13,181
Other	9,911	7,630
Total Net Deferred Tax Liabilities Before Valuation Allowance	(246,203)	(226,232)
Valuation Allowance	(1,442)	(1,806)
Total Net Deferred Tax Liabilities	$ (247,645)	$ (228,038)

Tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards. The Company has no liabilities for unrecognized tax benefits.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the years ended December 31, 2025, 2024 and 2023, the Company did not recognize any interest or penalties in its statements of operations, nor did it have any interest or penalties accrued in its balance sheet at December 31, 2025 and 2024 relating to unrecognized benefits.

The tax years 2025, 2024, 2023 and 2022 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject. Additionally, NOLs from 2011-2025 could be adjusted in the future when such NOLs are utilized.

NOTE 11 FAIR VALUE

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Financial Assets and Liabilities

As required, 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 Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2025 and 2024.

	Fair Value Measurements at December 31, 2025 Using				
(In thousands)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Effect of Counterparty Netting**	**Total**
Commodity Derivatives – Current Assets	$ —	$ 224,726	$ —	$ (58,100)	$ 166,626
Commodity Derivatives – Noncurrent Assets	—	30,986	—	(27,950)	3,036
Commodity Derivatives – Current Liabilities	—	(58,100)	—	58,100	—
Commodity Derivatives – Noncurrent Liabilities	—	(75,697)	—	27,950	(47,747)
Interest Rate Derivatives – Current Assets	—	52	—	—	52
Interest Rate Derivatives – Noncurrent Liabilities	—	(355)	—	—	(355)
Total	$ —	$ 121,612	$ —	$ —	$ 121,612

	Fair Value Measurements at December 31, 2024 Using				
(In thousands)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Effect of Counterparty Netting**	**Total**
Commodity Derivatives – Current Assets	$ —	$ 124,977	$ —	$ (78,612)	$ 46,365
Commodity Derivatives – Noncurrent Assets	—	60,874	—	(51,145)	9,729
Commodity Derivatives – Current Liabilities	—	(98,527)	—	78,612	(19,915)
Commodity Derivatives – Noncurrent Liabilities	—	(144,751)	—	51,145	(93,606)
Interest Rate Derivatives – Current Assets	—	160	—	—	160
Interest Rate Derivatives – Noncurrent Assets	—	103	—	—	103
Total	$ —	$ (57,164)	$ —	$ —	$ (57,164)

Commodity Derivatives. The Level 2 instruments presented in the tables above include commodity derivative instruments (see Note 12). The fair value of the Company's commodity derivative instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of commodity derivative contracts is reflected in the balance sheets. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Interest Rate Derivatives. The Level 2 instruments presented in the tables above include interest rate derivative instruments (see Note 12). The fair value of the Company's interest rate derivative instruments is determined based upon contracted notional amounts, active market-quoted interest yield curves, and time to maturity, among other things. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of interest rate derivative contracts is reflected in the balance sheets. The current interest rate derivative asset balances represent the fair values expected to be settled in the subsequent twelve months.

Fair Value of Other Financial Instruments

The carrying amounts of cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

Long-term debt is not presented at fair value in the balance sheets, as it is recorded at carrying value, net of unamortized debt issuance costs and unamortized premium (see Note 4). The fair value of the Company's Senior Notes due 2028, Convertible

Notes due 2029, Senior Notes due 2031 and Senior Notes due 2033 was $20.3 million, $675.4 million, $505.0 million, and $724.1 million respectively, at December 31, 2025. These fair values are based on market quotes that represent Level 2 inputs.

There is no active market for the Revolving Credit Facility. The recorded value of the Revolving Credit Facility approximates its fair value because of its floating rate structure based on the SOFR spread, secured interest, and the Company's borrowing base utilization. The fair value measurement for the Revolving Credit Facility represents Level 2 inputs.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the relevant accounting standards. The initial measurement of AROs at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the AROs liability is deemed to use Level 3 inputs. AROs incurred and acquired during the year ended December 31, 2025 were approximately $5.5 million.

The Company issued common stock warrants in January 2022 as a part of the purchase consideration for certain oil and natural gas properties acquired by the Company. Upon issuance, the Warrants granted holders the right to purchase 1,939,998 shares of the Company's common stock at an exercise price equal to $28.30 per share (subject to certain adjustments), generally exercisable from April 27, 2022 until January 27, 2029. A portion of the Warrants were surrendered and cancelled in March 2023, and the remaining Warrants were surrendered and cancelled in March 2024, in each case in exchange for shares of common stock. See Note 6. The fair value of the Warrants consideration was determined by utilizing an Option Pricing Model. These non-recurring fair value measurements are primarily determined using inputs that are observable or can be corroborated by observable market data (Level 2 inputs).

For all transactions accounted for as business combinations, the Company uses the acquisition method of accounting. In those instances, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of oil and natural gas properties. The fair value of these properties is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy. See Note 3 for additional discussion of the Company's acquisitions of oil and natural gas properties accounted for under the business combination method of accounting during the years ended December 31, 2025 and 2024, and discussion of the significant inputs to the valuations.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the years ended December 31, 2025 and 2024.

NOTE 12 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes various commodity price derivative instruments to (i) reduce the effects of volatility in price changes on the crude oil and natural gas commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending. In addition, from time to time the Company utilizes interest rate swaps to mitigate exposure to changes in interest rates on the Company's variable-rate indebtedness.

All derivative instruments are recorded in the Company's balance sheets as either assets or liabilities measured at their fair value (see Note 11). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value are recognized in the Company's statements of operations as a gain or loss on derivative instruments. Mark-to-market gains and losses represent changes in fair values of derivative instruments that have not been settled. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The Company has master netting agreements on individual derivative instruments with certain counterparties and therefore the current asset and liability are netted in the balance sheet and the non-current asset and liability are netted in the balance sheet for contracts with these counterparties.

Commodity Derivative Instruments

The following table presents settlements on commodity derivative instruments and unsettled gains and losses on open commodity derivative instruments for the periods presented which is recorded in the revenue section of our statements of operations:

	Year Ended December 31,		
(In thousands)	**2025**	**2024**	**2023**
Cash Received on Settled Derivatives	$ 201,321	$ 83,225	$ 57,919
Non-Cash Mark-to-Market Gain (Loss) on Derivatives	179,343	(21,258)	201,331
Gain on Commodity Derivatives, Net	$ 380,664	$ 61,967	$ 259,250

The following table summarizes open commodity derivative positions as of December 31, 2025, for commodity derivatives that were entered into through December 31, 2025, for the settlement periods presented:

	2026	2027	2028	2029
Oil:				
NYMEX WTI - Swaps:				
Volume (Bbl)	7,211,966	—	—	—
Weighted Average Price ($/Bbl)	$ 68.07	$ —	$ —	$ —
NYMEX WTI - Short Swaptions[(1)]:				
Volume (Bbl)	24,192,400	3,001,200	—	—
Weighted Average Price ($/Bbl)	$ 69.34	$ 70.77	$ —	$ —
NYMEX WTI - Long Swaptions[(1)]:				
Volume (Bbl)	803,000	—	—	—
Weighted Average Price ($/Bbl)	$ 65.75	$ —	$ —	$ —
Argus WTI Midland CMA DIFF - Basis Swaps:				
Volume (Bbl)	9,285,791	3,467,500	732,000	—
Weighted Average Price ($/Bbl)	$ 0.96	$ 0.80	$ 0.79	$ —
NYMEX WTI - Short Call Options[(1)]:				
Volume (Bbl)	2,701,365	4,420,515	2,602,300	—
Weighted Average Price ($/Bbl)	$ 73.18	$ 79.17	$ 71.39	$ —
NYMEX WTI - Long Call Options[(1)]:				
Volume (Bbl)	204,424	—	—	—
Weighted Average Price ($/Bbl)	$ 67.50	$ —	$ —	$ —
ICE Brent - Call Options [(1)]:				
Volume (Bbl)	—	—	316,590	—
Weighted Average Price ($/Bbl)	$ —	$ —	$ 80.00	$ —
NYMEX WTI CMA - Collars:				
Collar Put Volume (Bbl)	6,803,092	—	—	—
Collar Call Volume (Bbl)	9,263,307	—	—	—
Weighted Average Floor Price ($/Bbl)	$ 63.12	$ —	$ —	$ —
Weighted Average Ceiling Price ($/Bbl)	$ 72.24	$ —	$ —	$ —
Natural Gas:				
NYMEX Henry Hub - Swaps:				
Volume (MMBtu)	48,560,000	34,330,000	7,610,000	—
Weighted Average Price ($/MMBtu)	$ 4.09	$ 4.06	$ 3.85	$ —
Waha Gas Daily - Swaps:				
Volume (MMBtu)	1,825,000	1,825,000	155,000	—
Weighted Average Price ($/MMBtu)	$ 3.20	$ 2.98	$ 2.96	$ —
NYMEX Henry Hub - Short Swaptions [(1)]:				
Volume (MMBtu)	32,515,000	31,110,000	17,360,000	—
Weighted Average Price ($/MMBtu)	$ 4.34	$ 4.06	$ 4.01	$ —
NYMEX Henry Hub - Long Swaptions [(1)]:				
Volume (MMBtu)	—	7,320,000	—	—
Weighted-Average Price ($/MMBtu)	$ —	$ 4.00	$ —	$ —
Waha Basis - Swaps:				
Volume (MMBtu)	18,250,000	7,300,000	—	—

Weighted Average Price ($/MMBtu)	$ (0.84)	$ (0.87)	$ —	$ —
Waha Gas Daily Average vs Henry Hub Last Day				
Volume (MMBtu)	—	10,020,000	930,000	—
Weighted Average Price ($/MMBtu)	$ —	$ (1.01)	$ (1.01)	$ —
Waha Index - Swaps:				
Volume (MMBtu)	18,560,000	4,890,000	310,000	—
Weighted Average Price ($/MMBtu)	$ —	$ (0.01)	$ (0.02)	$ —
TETCO M2 Basis - Swaps:				
Volume (MMBtu)	29,045,000	15,065,000	8,560,000	7,300,000
Weighted Average Price ($/MMBtu)	$ (0.97)	$ (0.93)	$ (0.87)	$ (0.75)
TCO Basis - Swaps:				
Volume (MMBtu)	—	—	—	—
Weighted Average Price ($/MMBtu)	$ —	$ —	$ —	$ —
REX Zone 3 Basis - Swap:				
Volume (MMBtu)	14,615,000	12,775,000	7,320,000	3,650,000
Weighted Average Price ($/MMBtu)	$ (0.27)	$ (0.19)	$ (0.18)	$ (0.16)
NYMEX Henry Hub - Short Call Options [1]:				
Volume (MMBtu)	5,379,500	35,523,000	6,700,000	—
Weighted Average Price ($/MMBtu)	$ 5.60	$ 5.97	$ 4.50	$ —
NYMEX Henry Hub - Long Call Options [1]:				
Volume (MMBtu)	—	—	—	—
Weighted Average Price ($/MMBtu)	$ —	$ —	$ —	$ —
NYMEX Henry Hub - Collars:				
Collar Put Volume (MMBtu)	50,942,303	23,200,000	3,660,000	3,340,000
Collar Call Volume (MMBtu)	50,942,303	23,200,000	3,660,000	3,340,000
Weighted Average Floor Price ($/MMBtu)	$ 3.43	$ 3.45	$ 3.50	$ 3.50
Weighted Average Ceiling Price ($/MMBtu)	$ 4.98	$ 4.53	$ 4.15	$ 3.88
NGL:				
OPIS - Swaps:				
Volume (Bbl)	376,275	234,800	—	—
Weighted-Average Price ($/Bbl)	$ 33.90	$ 31.19	$ —	$ —

(1) Swaptions are crude oil and natural gas derivative contracts that give counterparties the option to extend certain derivative contracts for additional periods. Call Options are crude oil and natural gas derivative contracts sold by the Company that give counterparties the option to exercise certain derivative contracts. The volumes and prices reflected as Swaptions and Call Options in this table will only be effective if the options are exercised by the applicable counterparties.

Interest Rate Derivative Instruments

At times, the Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. The settlement of derivative instruments is recognized as a component of interest expense in the statements of operations. The mark-to-market component of these derivative instruments is recognized in gain (loss) on unsettled interest rate derivatives, net in the statements of operations. The following table summarizes our open interest rate derivative contracts as of December 31, 2025.

Fixed Rate Swap Agreements (in thousands)

	Swaps		
Contract Period	**Notional Amount**	**Fixed Rate**	**Floating Benchmark**
October 1, 2024 - October 1, 2026	$ 25,000	3.423 %	USD-SOFR CME
May 1, 2025 - May 1, 2027	$ 50,000	3.423 %	USD-SOFR CME
September 19, 2025 - October 1, 2027	$ 50,000	3.300 %	USD-SOFR CME
October 20, 2025 - November 1, 2027	$ 100,000	3.187 %	USD-SOFR CME
December 10, 2025 - December 1, 2027	$ 50,000	3.393 %	USD-SOFR CME
December 10, 2025 - December 1, 2028	$ 50,000	3.392 %	USD-SOFR CME

Other Information Regarding Derivative Instruments

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at December 31, 2025 and 2024, respectively. Certain amounts may be presented on a net basis in the financial statements when such amounts are with the same counterparty and subject to a master netting arrangement:

(In thousands)		December 31, Estimated Fair Value	
Type of Commodity	**Balance Sheet Location**	**2025**	**2024**
Derivative Assets:			
Commodity Price Swap Contracts	Current Assets	$ 103,943	$ 49,031
Commodity Basis Swap Contracts	Current Assets	41,142	21,419
Commodity Price Swaptions Contracts	Current Assets	1,428	5,398
Commodity Price Collar Contracts	Current Assets	71,571	46,839
Commodity Price Call Option Contracts	Current Assets	413	2,289
Commodity Price Index Swap Contracts	Current Assets	6,230	—
Interest Rate Swap Contracts	Current Assets	52	160
Commodity Price Swap Contracts	Noncurrent Assets	12,975	8,710
Commodity Basis Swap Contracts	Noncurrent Assets	5,330	16,513
Commodity Price Collar Contracts	Noncurrent Assets	12,680	35,652
Interest Rate Swap Contracts	Noncurrent Assets	—	103
Total Derivative Assets		$ 255,764	$ 186,114
Derivative Liabilities:			
Commodity Price Swap Contracts	Current Liabilities	$ (4,596)	$ (3,667)
Commodity Basis Swap Contracts	Current Liabilities	(6,137)	(5,150)
Commodity Price Swaptions Contracts	Current Liabilities	(25,987)	(44,174)
Interest Rate Swap Contracts	Current Liabilities	—	—
Commodity Price Collar Contracts	Current Liabilities	(17,229)	(29,668)
Commodity Price Call Option Contracts	Current Liabilities	(3,973)	(15,867)
Commodity Price Index Swap Contracts	Current Liabilities	(178)	—
Commodity Price Swap Contracts	Noncurrent Liabilities	(4,097)	(3,852)
Commodity Basis Swap Contracts	Noncurrent Liabilities	(10,177)	(2,564)
Commodity Price Swaptions Contracts	Noncurrent Liabilities	(25,111)	(44,315)
Commodity Price Collar Contracts	Noncurrent Liabilities	(11,332)	(36,327)
Commodity Price Call Option Contracts	Noncurrent Liabilities	(24,627)	(57,693)
Commodity Price Index Swap Contracts	Noncurrent Liabilities	(354)	—
Interest Rate Swaptions Contracts	Noncurrent Liabilities	(355)	—
Total Derivative Liabilities		$ (134,152)	$ (243,278)

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. When the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments these assets and liabilities are netted in the balance sheet. The tables presented below provide a reconciliation between the gross assets and liabilities and the amounts reflected in the balance sheets. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

(In thousands)	Estimated Fair Value at December 31, 2025 Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 224,778	$ (58,100)	$ 166,678
Non-Current Assets	30,986	(27,950)	3,036
Total Derivative Assets	$ 255,764	$ (86,050)	$ 169,714
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (58,100)	$ 58,100	$ —
Non-Current Liabilities	(76,052)	27,950	(48,102)
Total Derivative Liabilities	$ (134,152)	$ 86,050	$ (48,102)

(In thousands)	Estimated Fair Value at December 31, 2024 Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 125,137	$ (78,612)	$ 46,525
Non-Current Assets	60,977	(51,145)	9,832
Total Derivative Assets	$ 186,114	$ (129,757)	$ 56,357
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (98,527)	$ 78,612	$ (19,915)
Non-Current Liabilities	(144,751)	51,145	(93,606)
Total Derivative Liabilities	$ (243,278)	$ 129,757	$ (113,521)

All of the Company's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties that are also lenders under the Company's Revolving Credit Facility. The Company's obligations under the derivative instruments are secured pursuant to the Revolving Credit Facility, and no additional collateral had been posted by the Company as of December 31, 2025. The ISDAs may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. See Note 11 for the aggregate fair value of all derivative instruments at December 31, 2025 and 2024.

NOTE 13 EARNINGS PER SHARE

The reconciliation of the numerators and denominators used to calculate basic EPS and diluted EPS for the years ended December 31, 2025, 2024 and 2023 are as follows:

	December 31,		
(In thousands, except share and per share data)	**2025**	**2024**	**2023**
Net Income Attributable to Common Stock	$ 38,761	$ 520,308	$ 922,969
Weighted Average Common Shares Outstanding:			
Weighted Average Common Shares Outstanding – Basic	97,711,444	99,852,539	91,483,687
Plus: Dilutive Effect of Restricted Stock, Preferred Stock, Convertible Notes, and Common Stock Warrants	1,602,938	1,415,086	577,260
Weighted Average Common Shares Outstanding – Diluted	99,314,382	101,267,625	92,060,947
Net Income per Common Share:			
Basic	$ 0.40	$ 5.21	$ 10.09
Diluted	$ 0.39	$ 5.14	$ 10.03

SUPPLEMENTAL OIL AND GAS INFORMATION
(UNAUDITED)

Oil and Natural Gas Exploration and Production Activities

Oil and natural gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest, and other contractual provisions. Production expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include production and severance taxes. Depletion of crude oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts. The results of operations for the Company's crude oil and natural gas production activities are provided in the Company's related statements of income.

Costs Incurred and Capitalized Costs

The costs incurred in crude oil and natural gas acquisition, exploration and development activities are highlighted in the table below.

	December 31,		
(In thousands)	**2025**	**2024**	**2023**
Costs Incurred for the Year:			
Proved Property Acquisition and Other	$ 206,897	$ 924,454	$ 1,288,437
Unproved Property Acquisition	69,263	$ 23,363	$ 3,414
Development	901,581	936,959	639,203
Total	$ 1,177,741	$ 1,884,776	$ 1,931,054

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2025 by year incurred.

	December 31,			
(In thousands)	**2025**	**2024**	**2023**	**Prior Years**
Property Acquisition	$ 62,332	$ 17,661	$ 802	$ 5,239
Development	—	—	—	—
Total	$ 62,332	$ 17,661	$ 802	$ 5,239

Oil and Natural Gas Reserves and Related Financial Data

Information with respect to the Company's crude oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by the Company and audited by Cawley, our third-party independent reserve engineers.

Oil and Natural Gas Reserve Data

The following tables present the Company's estimates of its proved crude oil and natural gas reserves. The Company emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

(In thousands)	Natural Gas (MMCF)	Oil (MBBLS)	MBOE
Proved Developed and Undeveloped Reserves at December 31, 2022	1,008,407	162,741	330,808
Revisions of Previous Estimates	(166,121)	(33,954)	(61,641)
Extensions, Discoveries and Other Additions	67,796	28,123	39,422
Purchases of Minerals in Place	190,376	35,446	67,176
Production	(84,342)	(22,013)	(36,070)
Proved Developed and Undeveloped Reserves at December 31, 2023	1,016,116	170,342	339,695
Revisions of Previous Estimates	48,519	(5,116)	2,970
Extensions, Discoveries and Other Additions	98,001	20,465	36,798
Purchases of Minerals in Place	51,078	35,932	44,444
Production	(113,476)	(26,511)	(45,423)
Proved Developed and Undeveloped Reserves at December 31, 2024	1,100,238	195,112	378,484
Revisions of Previous Estimates	(26,797)	(7,055)	(11,519)
Extensions, Discoveries and Other Additions	246,393	17,770	58,836
Purchases of Minerals in Place	5,487	6,645	7,559
Production	(130,084)	(27,611)	(49,292)
Proved Developed and Undeveloped Reserves at December 31, 2025	1,195,237	184,861	384,068
Proved Developed Reserves:			
December 31, 2023	677,979	121,865	234,861
December 31, 2024	855,560	135,557	278,151
December 31, 2025	934,404	127,054	282,789
Proved Undeveloped Reserves:			
December 31, 2023	338,138	48,477	104,833
December 31, 2024	244,677	59,554	100,333
December 31, 2025	260,833	57,807	101,279

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

Notable changes in proved reserves for the year ended December 31, 2025 included the following:

- *Extensions and discoveries*. In 2025, total extensions and discoveries of 58.8 MMBoe were primarily attributable to successful drilling operations as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 31.4 MMBoe as a result of successful drilling operations and 27.4 MMBoe as a result of additional proved undeveloped locations.

- *Purchases of minerals in place*. In 2025, total purchases of minerals in place of 7.6 MMBoe were primarily attributable to acquisitions of oil and natural gas properties (see Note 3).

- *Revisions to previous estimates*. In 2025, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 11.5 MMBoe. Included in these revisions were 1.5 MMBoe of downward adjustments caused by lower crude oil and natural gas prices, 8.8 MMBoe of downward adjustments attributable to increased operating costs, 14.4 MMBoe of upward adjustments due to additions in proven areas, 4.7 MMBoe of upward adjustments attributable to well performance when comparing the Company's reserve estimates at December 31, 2025 to December 31, 2024 and 20.3 MMBoe of downward adjustments related to the removal of undeveloped drilling locations and other adjustments.

Notable changes in proved reserves for the year ended December 31, 2024 included the following:

- *Extensions and discoveries*. In 2024, total extensions and discoveries of 36.8 MMBoe were primarily attributable to successful drilling operations as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 14.1 MMBoe as a result of successful drilling operations and 22.7 MMBoe as a result of additional proved undeveloped locations.

- *Purchases of minerals in place*. In 2024, total purchases of minerals in place of 44.4 MMBoe were primarily attributable to acquisitions of oil and natural gas properties (see Note 3).

- *Revisions to previous estimates*. In 2024, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 3.0 MMBoe. Included in these revisions were 15.0 MMBoe of downward adjustments caused by lower crude oil and natural gas prices, an 8.0 MMBoe upward adjustment attributable to decreased operating costs, a 21.8 MMBoe upward adjustment due to additions in proven areas, a 0.1 MMBoe downward adjustment attributable to well performance when comparing the Company's reserve estimates at December 31, 2024 to December 31, 2023 and 11.7 MMBoe of downward adjustments related to the removal of undeveloped drilling locations related to the 5-year rule and other adjustments.

Notable changes in proved reserves for the year ended December 31, 2023 included the following:

- *Extensions and discoveries*. In 2023, total extensions and discoveries of 39.4 MMBoe were primarily attributable to successful drilling operations as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 14.8 MMBoe as a result of successful drilling operations and 24.6 MMBoe as a result of additional proved undeveloped locations.

- *Purchases of minerals in place*. In 2023, total purchases of minerals in place of 67.2 MMBoe were primarily attributable to acquisitions of oil and natural gas properties (see Note 3).

- *Revisions to previous estimates*. In 2023, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 61.6 MMBoe. Included in these revisions were 28.3 MMBoe of downward adjustments caused by lower crude oil and natural gas prices, a 2.7 MMBoe downward adjustment attributable to increased operating costs, a 3.9 MMBoe downward adjustment attributable to well performance when comparing the Company's reserve estimates at December 31, 2023 to December 31, 2022 and 26.7 MMBoe of downward adjustments related to the removal of undeveloped drilling locations related to the 5-year rule and other adjustments.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves, and the changes in standardized measure of discounted future net cash flows relating to proved crude oil and natural gas were prepared in accordance with the provisions of ASC 932 *Extractive Activities - Oil and Gas*. Future cash inflows were computed by applying average prices of crude oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses were calculated by applying appropriate year-end tax rates to future pretax cash flows relating to proved crude oil and natural gas reserves, less the tax basis of properties involved and tax credits and loss carry forwards relating to crude oil and natural gas producing activities. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted future cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the Company's crude oil and natural gas reserves. All estimated future costs to settle the Company's asset retirement obligations have been included in our calculation of the standardized measure for each period presented.

	December 31,		
(In thousands)	**2025**	**2024**	**2023**
Future Cash Inflows	$ 14,842,258	$ 15,999,589	$ 16,008,048
Future Production Costs	(6,311,737)	(6,534,021)	(6,627,373)
Future Development Costs	(1,247,323)	(1,443,878)	(1,358,405)
Future Income Tax Expense	(992,693)	(1,324,433)	(1,380,854)
Future Net Cash Inflows	$ 6,290,505	$ 6,697,258	$ 6,641,417
10% Annual Discount for Estimated Timing of Cash Flows	(2,467,703)	(2,466,336)	(2,485,180)
Standardized Measure of Discounted Future Net Cash Flows	$ 3,822,802	$ 4,230,922	$ 4,156,237

The twelve-month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the Company's reserves. The price of other liquids is included in natural gas. The prices for the Company's reserve estimates were as follows:

	Natural Gas MCF	**Oil Bbl**
December 31, 2025	$ 3.18	$ 59.72
December 31, 2024	$ 2.02	$ 70.60
December 31, 2023	$ 3.10	$ 75.51

The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows. As a result of available net operating loss carryforwards and the remaining tax basis of its assets at December 31, 2025, the Company's future income taxes were significantly reduced.

Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum follow:

	December 31,		
(In thousands)	**2025**	**2024**	**2023**
Beginning of Period	$ 4,230,922	$ 4,156,237	$ 6,436,898
Sales of Oil and Natural Gas Produced, Net of Production Costs	(1,476,288)	(1,565,196)	(1,390,656)
Extensions and Discoveries	532,515	481,810	683,258
Previously Estimated Development Cost Incurred During the Period	333,517	462,375	327,768
Net Change of Prices and Production Costs	(318,899)	(517,053)	(3,241,176)
Change in Future Development Costs	106,912	(62,361)	(237,627)
Revisions of Quantity and Timing Estimates	(189,286)	(211,356)	(1,061,840)
Accretion of Discount	506,985	500,409	790,216
Change in Income Taxes	131,074	8,921	617,405
Purchases of Minerals in Place	234,639	929,740	1,200,155
Other	(269,289)	47,396	31,835
End of Period	$ 3,822,802	$ 4,230,922	$ 4,156,237

Appendix A

Non-GAAP Reconciliations

Adjusted EBITDA (In thousands)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)	2025 ($)
Net Income (Loss)	**(906,041)**	**6,361**	**773,237**	**922,969**	**520,308**	**38,761**
Add:						
Interest Expense	58,503	59,020	80,331	135,664	157,717	172,380
Income Tax Provision (Benefit)	(166)	233	3,101	77,773	160,509	23,944
Depletion, Depreciation, Amortization, and Accretion	162,120	140,828	251,272	486,024	740,901	814,859
Write off of Debt Issuance Costs	1,543	—	—	—	—	—
(Gain) Loss on the Extinguishment of Debt	3,718	13,087	(810)	(659)	—	10,833
Contingent Consideration (Gain) Loss	169	292	(1,859)	(10,107)	—	—
Impairment of Oil and Gas Assets	1,066,668	—	—	—	—	702,747
Acquisition Transaction Costs	—	8,190	16,593	11,243	1,742	3,001
Other Adjustments	—	—	—	—	5,116	25,719
(Gain) Loss on Unsettled Interest Rate Derivatives	1,019	(1,043)	(993)	1,017	(263)	566
(Gain) Loss on Unsettled Commodity Derivatives	(39,878)	312,370	(40,187)	(201,331)	21,258	(179,343)
Non-Cash Share Based Compensation	4,119	3,621	5,656	5,660	11,858	15,363
Adjusted EBITDA	**351,774**	**542,959**	**1,086,341**	**1,428,254**	**1,619,147**	**1,628,831**

Free Cash Flow (In thousands)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)	2025 ($)
Net Cash Provided by Operating Activities	**331,685**	**396,467**	**928,418**	**1,183,321**	**1,408,663**	**1,505,288**
Exclude: Changes in Working Capital and Other Items	(34,136)	85,813	62,400	106,134	53,886	(70,063)
Less: Capital Expenditures(1)	(212,051)	(253,479)	(523,061)	(926,547)	(1,001,306)	(1,011,250)
Less: Series A Preferred Dividends	(15,266)	(14,761)	(9,803)	—	—	—
Free Cash Flow	**70,232**	**214,040**	**457,954**	**362,908**	**461,243**	**423,975**
(1) Capital Expenditures are calculated as follows:						
Cash Paid for Capital Expenditures	283,632	614,222	1,355,197	1,861,134	1,674,626	1,251,703
Less: Non-Budgeted Acquisitions	—	(389,657)	(880,935)	(973,433)	(862,321)	(230,490)
Plus: Change in Accrued Capital Expenditures and Other	(71,581)	28,914	48,798	38,847	189,002	(9,963)
Capital Expenditures	**212,051**	**253,479**	**523,061**	**926,547**	**1,001,306**	**1,011,250**

Return on Capital Employed (ROCE) (In thousands)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)	2025 ($)
Adjusted EBIT						
Adjusted EBITDA	351,773	542,959	1,086,341	1,428,254	1,619,147	1,628,831
Less: Depletion, Depreciation, Amortization, and Accretion	203,142	225,633	329,797	486,024	740,901	832,393
Adjusted EBIT	**148,631**	**317,326**	**756,545**	**942,230**	**878,246**	**796,437**
Capital Employed						
Average Total Assets	1,901,600	2,180,720	3,100,600	3,679,716	5,044,039	5,849,205
Less: Average Current Liabilities	192,976	255,016	336,265	365,367	465,015	541,781
Capital Employed	**1,708,624**	**1,925,704**	**2,764,335**	**3,314,349**	**4,579,023**	**5,307,425**
ROCE						
Adjusted EBIT	148,631	317,326	756,545	942,230	878,246	796,437
Divided by: Capital Employed	1,708,624	1,925,704	2,764,335	3,314,349	4,579,023	5,307,425
ROCE	**8.7%**	**16.5%**	**27.4%**	**28.4%**	**19.2%**	**15.0%**

Net Debt (In thousands)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)	2025 ($)
Principal Amount of Debt Outstanding at year-end	805,000	805,000	1,543,200	1,866,100	2,395,100	2,423,200
Less: Cash and Acquisition Deposits at year-end	(1,428)	(50,169)	(45,528)	(25,289)	(8,900)	(73,099)
Net Debt at year-end	**803,572**	**754,831**	**1,497,672**	**1,840,811**	**2,386,200**	**2,350,101**

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