UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 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 001-42499

INFINITY NATURAL RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**99-3407012** (I.R.S. Employer Identification No.)
2605 Cranberry Square, Morgantown, West Virginia (Address of Principal Executive Offices)	**26508** (Zip Code)

(304) 212-2350
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
Class A common stock, par value $0.01 per share	INR	The 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 Act).

Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant as of June 30, 2025, the last business day of the registrant’s most recently completed second fiscal quarter, was approximately $277,442,275 based on the closing price of the shares of Class A common stock on that date.

The number of shares of the Registrant’s Class A common stock and Class B common stock outstanding as of March 5, 2026 was 18,165,700 and 45,247,974, respectively.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Some of the information in this Annual Report on Form 10-K (this "Annual Report") may contain "forward-looking statements." All statements, other than statements of historical fact included in this Annual Report regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, words such as "may," "assume," "forecast," "could," "should," "will," "plan," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget" and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events at the time such statement was made. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation" included in this Annual Report. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- oil, natural gas and NGL prices;
- our business strategy;
- our ability to integrate operations or realize any anticipated operational or corporate synergies and other benefits of our acquisitions, including the Antero Acquisition;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our estimated proved reserves;
- our ability to achieve or maintain certain financial and operational metrics;
- our drilling prospects, inventories, projects and programs;
- actions taken by the OPEC and other allied countries (collectively known as "OPEC+") as it pertains to the global supply and demand of, and prices for, oil, natural gas and NGLs;
- armed conflict, political instability or civil unrest in oil and gas producing regions, including armed conflict and instability in the Middle East, Venezuela, Mexico and the conflict between Russia and Ukraine, and the related potential effects on laws and regulations, or the imposition of economic or trade sanctions;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- the occurrence or threat of epidemic or pandemic diseases, or any government response to such occurrence or threat;
- risks and restrictions related to our debt agreements and the level of our indebtedness;
- risks and restrictions related to our Series A Preferred Stock;
- our financial strategy, leverage, liquidity and capital required for our development program;
- our pending legal matters;
- our ability to comply with environmental, health and safety laws, regulations and obligations;
- our price differentials;
- our ability to reduce or offset our GHG emissions, including our ability to achieve carbon neutrality;
- our hedging strategy and results;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;

- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties incident to the development, production, gathering and sale of oil, natural gas and NGLs, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, commodity price volatility; inflation; lack of availability and cost of drilling, completion and production equipment and services; supply chain disruption; project construction delays; environmental risks; drilling, completion and other operating risks; lack of availability or capacity of midstream gathering and transportation infrastructure; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital; the timing of development expenditures, impacts of geopolitical and world health events; cybersecurity risks; and the other risks described under "Item 1A. Risk Factors."

Reserve engineering is a process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimates depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any future production and development program. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

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

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

ABOUT THIS ANNUAL REPORT

Financial Statement Presentation

Infinity Natural Resources, Inc. (the "Company") was incorporated as a Delaware corporation on May 15, 2024. Prior to the completion of its initial public offering (the "IPO") on February 3, 2025, Infinity Natural Resources, Inc. undertook certain reorganization transactions (the "Corporate Reorganization") such that Infinity Natural Resources, Inc. is now a holding company, whose sole material asset consists of membership interests in Infinity Natural Resources, LLC, a Delaware limited liability company ("INR Holdings"). INR Holdings owns all of the outstanding membership interests in each of INR Operating, INR Ohio, INR Midstream, Block Island and Cheat Mountain, the operating subsidiaries through which INR Holdings operates its assets. Infinity Natural Resources, Inc. is the managing member of INR Holdings and controls and is responsible for all operational, management and administrative decisions relating to INR Holdings business and consolidates the financial results of INR Holdings and reports non-controlling interests in its consolidated financial statements related to the INR Units that the Legacy Owners own in INR Holdings. For periods prior to the Corporate Reorganization, the historical consolidated financial statements included in this Annual Report are based on the financial statements of our predecessor, INR Holdings.

COMMONLY USED DEFINED TERMS

As used in this Annual Report, unless the context indicates or otherwise requires, the terms listed below have the following meanings:

- “Block Island” refers to Block Island Minerals LLC, a subsidiary of INR Holdings;
- “Carroll County Acquisition” refers to INR Holdings’ acquisition of the Warrior North field from PennEnergy Resources, Inc. in April 2021;
- “Cheat Mountain” refers to Cheat Mountain Resources, LLC, a subsidiary of INR Holdings;
- “Credit Agreement” refers to that certain Credit Agreement, dated September 25, 2024, by and among INR Holdings, the lenders from time to time party thereto and Citibank, N.A., as the administrative agent and an issuing bank as amended from time to time;
- “Credit Facility” refers to the revolving credit facility provided under our Credit Agreement;
- “INR Holdings” refers to Infinity Natural Resources, LLC, a Delaware limited liability company, and the entity that holds the Company’s operating entities;
- “INR Holdings LLC Agreement” refers to the Second Amended and Restated Limited Liability Company Agreement of INR Holdings, as amended;
- “Infinity Natural Resources,” “Infinity,” “INR,” the “Company,” “we,” “our,” “us” or like terms refer collectively to Infinity Natural Resources, Inc. and its consolidated subsidiaries, unless the context otherwise indicates;
- “INR Ohio” refers to INR Ohio, LLC, a subsidiary of INR Holdings;
- “INR Midstream” refers to INR Midstream, LLC, a subsidiary of INR Holdings;
- “INR Operating” refers to INR Operating, LLC, a subsidiary of INR Holdings;
- “INR Unit Holder” refers to a holder of INR Units (other than INR) and a corresponding number of shares of Class B common stock of INR;
- “INR Units” refers to units representing limited liability company interests in INR Holdings issued pursuant to the INR Holdings LLC Agreement, which shall only be held along with a corresponding number of shares of Class B common stock of INR (other than those held by INR);
- “Legacy Owners” refers, collectively, to Pearl, NGP, certain other co-investors and the management members that directly and indirectly own equity interests in INR Holdings or its wholly owned subsidiaries following the completion of our Corporate Reorganization;
- “LLC Interests” refers to the limited liability company interests of INR Holdings;
- “NGP” refers to a family of private equity funds managed by NGP Energy Capital Management, L.L.C., including NGP XI US Holdings, L.P.;
- “Ohio Utica Acquisition” refers to Infinity’s acquisition of assets from Utica Resource Ventures and PEO Ohio in October 2023;
- “Pearl” refers to Pearl Energy Investments, L.P., PEI INR Holdings, L.P., Pearl Energy Investments III, L.P., PEI Infinity-S, LP, PEI INR Co-Invest-B Corp and their affiliates;
- “PEO Ohio” refers to PEO Ohio, LLC; and
- “Utica Resource Ventures” refers to Utica Resource Ventures, LLC.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

- “Appalachian Basin” means the area of the United States composed of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky, New York, Tennessee and Virginia that lie in amongst Appalachian Mountains;
- “basis” means when referring to commodity pricing, the difference between the NYMEX WTI, for oil prices, and NYMEX Henry Hub, for gas prices, and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location, transportation capacity availability and contract pricing;
- “Bbl” means one stock tank barrel or 42 U.S. gallons liquid volume;
- “Bcf” means one billion standard cubic feet of natural gas;
- “Boe” means one barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil equivalent. This is an energy content correlation and does not reflect a value or price relationship between the commodities;
- “Boe/d” means one Boe per day;
- “British thermal unit” or “Btu” means a measure of the amount of energy required to raise the temperature of one pound of water by one-degree Fahrenheit;
- “CO_2” means carbon dioxide;
- “collar” means a financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk and benefit of fluctuation between the minimum (floor) price and the maximum (ceiling) price;
- “drilled and uncompleted well” or “DUC” means a wellbore in which horizontal drilling has been completed but has yet to be stimulated through hydraulic fracturing;
- “drilling locations” means total gross locations that may be able to be drilled on our existing acreage. A portion of our drilling locations constitute estimated locations based on our acreage and spacing assumptions, as described in “Item 1. Business”;
- “estimated ultimate recovery” or “EUR” means the sum of the economic life of reserves remaining as of a given date and cumulative production as of that date. As used in this Annual Report, EUR includes only proved reserves and is based on Wright’s reserve estimates;
- “FERC” means the Federal Energy Regulatory Commission;
- “field” means 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” means a layer of rock which has distinct characteristics that differs from nearby rock;
- “gas” means natural gas;
- “gross” means “gross” natural gas and oil wells or “gross” acres equal to the total number of wells or acres in which we have a working interest;
- “HBP” means held-by-production;
- “hedging” means the use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility;
- “held-by-storage” means leasehold held through a declared storage field, injection well, or simply held by storage rights;
- “Henry Hub” means the distribution hub on the natural gas pipeline system in Erath, Louisiana, owned by Sabine Pipe Line LLC;

- “horizontal drilling” means drilling that ultimately is horizontal or near horizontal to increase the length of the wellbore penetrating the target formation;
- “horizontal wells” means wells that are drilled horizontal or near horizontal to increase the length of the wellbore penetrating the target formation;
- “LNG” means liquified natural gas;
- “lower 48” means the continental United States, excluding Alaska and Hawaii;
- “MBoe” means one thousand barrels of oil equivalent;
- “MBoe/d” means one thousand barrels of oil equivalent per day;
- “Mcf” means one standard thousand cubic feet of natural gas;
- “MMBbl” means one million barrels of crude oil, condensate or NGLs;
- “MMBoe” means one million barrels of oil equivalent;
- “MMBtu” means one million British thermal units;
- “MMBtu/d” means one MMBtu per day;
- “MMcf” means one million standard cubic feet of natural gas;
- “MMcf/d” means one million standard cubic feet of natural gas per day;
- “natural gas liquids” or “NGLs” means hydrocarbons – in the same family of molecules as natural gas and crude oil, composed exclusively of carbon and hydrogen. Ethane, propane, butane, isobutane, and pentane are all NGLs;
- “net acres” means the percentage of total acres an owner owns or has leased out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres;
- “NYMEX” means the New York Mercantile Exchange;
- “option” means a contract that gives the buyer the right, but not the obligation, to buy or sell a specified quantity of a commodity or other instrument at a specific price within a specified period of time;
- “proved developed nonproducing reserves” or “PDNP” reserves that can be expected to be recovered through existing wells with existing equipment and operating methods but are not yet producing;
- “proved developed producing reserves” or “PDP” means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, according to the Securities and Exchange Commission or Society of Petroleum Engineers definitions of proved reserves;
- “proved reserves” means the summation of reserves within the PDP, PDNP and PUD reservoir categories;
- “proved undeveloped reserves” or “PUDs” means proved reserves that are expected to be recovered from undrilled well locations on existing acreage or from existing wells where a relatively major expenditure is required for recompletion within the five-year development window, according to the Securities and Exchange Commission or Society of Petroleum Engineers definition of PUD;
- “recompletion” means the process of re-entering an existing wellbore and mechanically reinvigorating the wellbore to establish or increase existing production and reserves;
- “reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock and is separate from other reservoirs;
- “spacing” means the footage between wellbores;
- “statutory unitization” means the process prescribed by Ohio Revised Code Section 1509.28, by which an applicant (typically an operator) may seek to combine mineral rights from individual tracts of land to form a drilling unit to efficiently and effectively develop the oil and gas resources beneath those tracts. Statutory unitization is available when the owners of sixty-five percent of the land overlying a pool (or part of a pool) of oil and gas apply to the Ohio Department of Natural Resources Division of Oil and Gas Resources Management to operate the pool (or part of a pool) as a drilling unit;
- “undeveloped acreage” means acreage under lease on which wells have not been drilled or completed;

- "unit" means the joining of all or substantially all interests in a specific reservoir or field, rather than a single tract, to provide for development and operation without regard to separate mineral interests. Also, the area covered by a unitization agreement;
- "well pad" or "pad" means an area of land that has been cleared and leveled to enable a drilling rig to operate in the exploration and development of a natural gas or oil well;
- "wellbore" or "well" means a drilled hole that is equipped for the production of hydrocarbons;
- "working interest" means the right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis; and
- "WTI" means West Texas Intermediate.

RISK FACTORS SUMMARY

Risks Related to Commodity Prices

- Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition and results of operations, liquidity and our ability to meet our financial commitments or cause us to delay our planned capital expenditures.
- We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.
- Certain factors could require us to write down the carrying values of our properties, including commodity prices decreasing to a level such that our future undiscounted cash flows from our properties are less than their carrying value.

Risks Related to Our Reserves, Leases and Drilling Locations

- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- Unless we replace our reserves with new reserves and develop those new reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.
- Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.
- Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- Properties that we decide to drill may not yield oil, natural gas and NGLs in commercially viable quantities.

Risks Related to Our Operations

- We may be unable to integrate the recently acquired Antero Ohio Assets (as defined herein) successfully, or realize the anticipated benefits of the acquisition.
- Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.
- Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.
- Our ability to produce oil, natural gas and NGLs economically and in commercial quantities is dependent on the availability of adequate supplies of water for drilling and completion operations and access to water and waste disposal or recycling facilities and services at a reasonable cost. Restrictions on our ability to obtain water or dispose of produced water and other waste may have an adverse effect on our financial condition, results of operations and cash flows.
- The marketability of certain of our production is dependent upon transportation and other facilities, which we do not control. If these facilities are unavailable, or if there are any increases in the cost of using these services or facilities, our operations could be interrupted, our revenues could be reduced and our costs could increase.
- The unavailability or high cost of drilling rigs, completion crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.
- We may incur losses as a result of title defects in the properties in which we invest.
- Future legislation or changes in tax laws and regulations may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and production. Additionally, future federal or state regulations or legislation may impose new or increased costs, including taxes or fees, on oil and natural gas extraction, transportation and sales.
- Changes in effective tax rates, or adverse outcomes resulting from other tax increases or an examination of our income or other tax returns, could adversely affect our results of operations and financial condition.
- Continuing or worsening inflationary pressures and associated changes in monetary policy may result in increases to the cost of our goods, services, and personnel, which in turn could cause our capital expenditures and operating costs to rise.
- Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

- Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are subject to risk and uncertainties, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition.
- Competition in our industry is intense, making it more difficult for us to acquire properties, market oil, natural gas and NGLs, secure trained personnel and raise additional capital.
- The loss of senior management or technical personnel could adversely affect operations.
- Loss of our information and computer systems could adversely affect our business.
- Cyberattacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.
- We previously identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future which, if not corrected, could affect the reliability of our consolidated financial statements and have other adverse consequences.

Risks Related to Our Derivative Transactions, Debt and Access to Capital

- Our derivative activities could result in financial losses or could reduce our earnings.
- The failure of our hedge counterparties, significant customers or working interest holders to meet their obligations to us may adversely affect our financial results.
- Our ability to obtain financing on terms acceptable to us may be limited in the future by, among other things, increases in interest rates.
- The borrowing base under our Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs.

Risks Related to our Class A Common Stock, Series A Preferred Stock and Capital Structure

- We are a holding company. Our sole material asset is our equity interest in INR Holdings and we are accordingly dependent upon distributions from INR Holdings to pay taxes, make payments under the Tax Receivable Agreement (as defined herein) and cover our corporate and other overhead expenses.
- Pearl, NGP, Quantum and Carnelian collectively hold a substantial majority of our capital stock and voting power.
- Conflicts of interest could arise in the future between us and Pearl, NGP, Quantum and Carnelian and their respective affiliates, including their portfolio companies concerning conflicts over our operations or business opportunities.
- Our Series A Preferred Stock (as defined herein) has rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our Class A common stock.
- Our amended and restated certificate of incorporation, amended and restated bylaws and Certificate of Designation (as defined herein), as well as Delaware law, contains provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our Class A common stock.
- The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.
- We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may claim, and the amounts of such payments could be significant.
- In certain circumstances, INR Holdings will be required to make tax distributions to us and the INR Unit Holders, and the tax distributions that INR Holdings will be required to make may be substantial.

Risks Related to Environmental and Regulatory Matters

- Our operations are subject to stringent environmental, health and safety laws and regulations that may expose us to significant costs and liabilities that could exceed current expectations.
- Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, limits to the areas in which we can operate and reductions in our oil, natural gas and NGL production, which could adversely affect our production and business.
- We are subject to risks related to climate change, which could have a material adverse effect on our business, financial condition and results of operations.

PART I

ITEM 1. BUSINESS

Overview

We are a growth oriented independent energy company focused on the acquisition, development, and production of hydrocarbons in the Appalachian Basin. We are focused on creating shareholder value through the identification and disciplined development of low-risk, highly economic oil and natural gas assets while maintaining a strong and flexible balance sheet. Our operations are focused on the Utica Shale in eastern Ohio as well as our dry gas assets in both the Marcellus and Utica Shales in southwestern Pennsylvania, providing highly economic stacked development inventory that leverages shared infrastructure and operational efficiencies. Our portfolio is balanced across oil and natural gas assets, allowing us to optimize our development plan to respond to changes in commodity prices over time. Unless expressly stated otherwise, the operating and financial information presented in this Annual Report does not give effect to the completion of the Antero Acquisition or the Preferred Investment (each as defined herein).

Our corporate headquarters are in Morgantown, WV, and shares of our Class A common stock trade on the New York Stock Exchange (the "NYSE") under the ticker symbol "INR".

Antero Acquisition

On February 23, 2026, we completed the acquisitions ("Antero Acquisition") of (i) certain rights, title and interests in upstream oil and gas properties, rights and related assets located in the State of Ohio (the "Upstream Assets") from Antero Resources Corporation, Antero Minerals LLC and Monroe Pipeline LLC (collectively, the "Upstream Sellers"), pursuant to that certain purchase and sale agreement (the "Upstream Purchase Agreement"), dated December 5, 2025, by and among INR Holdings, Northern Oil and Gas Inc. ("Northern") and the Upstream Sellers, for a combined cash purchase price of approximately $800 million and (ii) certain gathering, compression and transportation systems, water facilities and systems, equipment and related assets located in the counties of Belmont, Guernsey, Monroe, Noble and Washington, Ohio (the "Midstream Assets" and, together with the Upstream Assets, the "Antero Ohio Assets") from Antero Midstream LLC, Antero Water LLC and Antero Treatment LLC (collectively, the "Midstream Sellers") pursuant to that certain purchase and sale agreement (the "Midstream Purchase Agreement" and, together with the Upstream Purchase Agreement, the "Antero Purchase Agreements"), dated December 5, 2025, by and among INR Holdings, Northern and the Midstream Sellers, for a combined cash purchase price of approximately $400 million. We acquired an undivided 60% interest and Northern acquired an undivided 40% interest in each of the Upstream Assets and Midstream Assets.

The Upstream Assets include approximately 42,500 net surface acres in the Ohio Utica Shale across Guernsey, Noble, Belmont, and Monroe Counties, which are highly contiguous with and complementary to our existing Ohio operations. The assets include an estimated 370.1 Bcfe of proved reserves and approximately 110 identified undeveloped drilling locations across multiple phase windows.

The Midstream Assets include approximately 141 miles of natural gas gathering pipelines, with capacity to support up to 600 MMcf/d, and approximately 90 miles of freshwater and produced-water infrastructure. These assets enhance our vertical integration and are expected to reduce operating costs, improve margins, and enable efficient full-field development.

Infinity will operate substantially all of the Antero Ohio Assets pursuant to joint development and cooperation agreements entered into with Northern at closing. We funded the transaction with cash on hand, the proceeds of the Preferred Investment and borrowings under our Credit Facility, which was amended and expanded in connection with closing.

Preferred Investment

On February 23, 2026, Infinity issued and sold, pursuant to a Securities Purchase Agreement ("Securities Purchase Agreement") an aggregate 350,000 shares of Series A Convertible Preferred Stock of the Company, par value $0.01 per share ("Series A Preferred Stock") to affiliates of Quantum Capital Group ("Quantum") and affiliates of Carnelian Energy Capital Management, L.P. ("Carnelian") (each a "Preferred Purchaser" and, collectively, the "Preferred Purchasers") for consideration of $350 million. After deducting placement agent fees, Infinity received net proceeds of approximately $337.1 million. Quantum acquired 275,000 shares of Series A Preferred Stock and Carnelian acquired 75,000 shares of Series A Preferred Stock (the "Preferred Investment"). The Company used the proceeds of the Preferred Investment to fund a portion of the Antero Acquisitions and will use any remaining proceeds for general corporate purposes.

Initial Public Offering

On February 3, 2025, we completed our IPO of 15,237,500 shares of our Class A common stock, par value $0.01 per share ("Class A common stock"), which includes 1,987,500 shares of Class A common stock issued and sold pursuant to the underwriters' exercise of their option in full to purchase additional shares of Class A common stock, at a price to the public of $20.00 per share ($18.80 per share net of underwriting discounts and commissions). After deducting underwriting discounts and commissions, we received net proceeds of approximately $286.5 million. We contributed all of the net proceeds from the IPO to INR Holdings. In turn, INR Holdings used all of the net proceeds from the IPO (net of underwriting discounts) after paying certain offering expenses to repay $285.0 million of outstanding borrowings under the Credit Facility.

Corporate Reorganization

In connection with the IPO, we underwent a Corporate Reorganization whereby: (a) the membership interests of the Legacy Owners in INR Holdings (including the Incentive Units, as defined in Item 11. "Executive Compensation—Narrative Disclosure to Summary Compensation Table—Long-Term Equity Incentive Compensation") were recapitalized into a single class of units (the "INR Units"), and, in exchange for their existing membership interests, the Legacy Owners received INR Units and an equal number of shares of Class B common stock, par value $0.01 per share ("Class B common stock"); and (b) we contributed the net proceeds of the IPO to INR Holdings in exchange for newly issued INR Units and a managing member interest in INR Holdings. Infinity is a holding company whose sole material asset consists of membership interests in INR Holdings. Infinity is the managing member of INR Holdings and controls and is responsible for all operational, management and administrative decisions relating to INR Holdings' business and consolidates the financial results of INR Holdings and reports non-controlling interests in its consolidated financial statements related to the INR Units that the Legacy Owners own in INR Holdings. As of December 31, 2025, we owned an approximate 25.6% common interest in INR Holdings and the Legacy Owners owned an approximate 74.4% common interest in INR Holdings.

Our Operations and Acreage

Our operations are focused on the Utica Shale in eastern Ohio as well as the Marcellus Shale and the emerging dry gas Utica Shale in southwestern Pennsylvania. As of December 31, 2025, we held approximately 98,400 net surface acres across our core operating areas. The following table provides a summary of our approximate net acreage, net operated producing wells and gross drilling locations separated by shale (including acreage prospective for dual-zone development):

	As of December 31, 2025		
	Net Horizon Acres(1)	Operated Producing Wells (#)	Drilling Locations (#)
Utica Shale Oil (OH)	64,152	129	129 (3)
Marcellus Shale Dry Gas (PA)(2)	33,925	25	107
Utica Shale Deep Dry Gas (PA)(2)	33,226	—	66

(1) Does not include 15,677 net acres located in the Marcellus Shale in Ohio that is not part of our development plan.

(2) The acreage in this table reflects net horizon acres. Substantially all of our surface acreage in Pennsylvania is prospective for both the Utica and Marcellus Shales for dual-zone development. As a result, most of our net surface acres represent one horizon acre for the Utica Shale and one horizon acre for the Marcellus Shale. Our total net surface acreage irrespective of dual-zone development was 98,419 net acres and our total horizon acres were 131,303. See "Business—Our Operations—Acreage as of December 31, 2025" for information regarding our undeveloped and developed surface acreage.

(3) Includes 6 PDNP wells and 8 DUCs.

Utica Shale Oil – Ohio

We hold a significant acreage position in Ohio centered in the volatile oil window of the Utica Shale, primarily in Guernsey, Carroll, Noble, Morgan, and Washington Counties. As of December 31, 2025, we held approximately 64,000 net acres in this operating area. Subsequent to year-end, we completed the Antero Acquisition, which added approximately

42,500 net surface acres attributable to our 60% undivided interest across Guernsey, Belmont, and Harrison Counties. Including the Antero Ohio Assets, our total net acreage position in the Ohio Utica Shale increased to approximately 107,000 net surface acres.

We have 129 producing horizontal wells, six PDNP wells and eight DUCs in this operating area with net daily production of 22.8 MBoe/d in 2025. We intend to operate 100% of our future drilling locations and approximately 82% of our acreage is HBP.

Marcellus Shale Dry Gas and Utica Deep Dry Gas – Pennsylvania

Our Pennsylvania properties, which we initially acquired in March 2018, are predominately located to the northeast of Pittsburgh in Westmoreland, Armstrong and Indiana counties. We have expanded our leasehold position through a series of subsequent acquisitions and have amassed approximately 34,000 net surface acres with exposure to both Marcellus and Utica Shales. Our development of the Marcellus Shale overlies the deep dry gas Utica Shale underneath providing us dual horizon development as well as the opportunity to further leverage our wholly owned midstream system in this area. While early in its development, the deep dry gas Utica continues to emerge and show highly attractive commercial characteristics. As of February 2026, we have one outstanding permit to drill a deep dry gas Utica Shale well in Armstrong County, Pennsylvania. Our contiguous HBP acreage and company-owned midstream infrastructure allow us to maximize the economics of the stacked Marcellus and Utica plays.

We have 25 producing horizontal wells in this operating area with net daily production of 12.5 MBoe/d in 2025. We intend to operate 100% of our future drilling locations and approximately 98% of our acreage is HBP or held-by-storage.

Our Properties

Oil, Natural Gas and NGL Reserves

The information with respect to our estimated reserves has been prepared in accordance with the rules and regulations of the SEC. Our estimated proved reserves as of December 31, 2025 and 2024 are based on valuations prepared by our independent reserve engineer, Wright & Company, Inc. ("Wright"). Copies of the summary reports of our reserve engineers as of December 31, 2025 and 2024 are filed as exhibits to this Annual Report. "—Preparation of Reserve Estimates" below contains additional definitions of proved reserves and the technologies and economic data used in their estimation. The following tables summarize estimated reserves based on reports prepared by Wright. The information in the following tables does not give any effect to or reflect our commodity hedge portfolio.

Summary of Reserves as of December 31, 2025 and 2024 Based on SEC Pricing

The following table provides the estimated reserves of INR Holdings as of December 31, 2025 and 2024 based on SEC pricing:

	December 31, 2025(1)	December 31, 2024[(2)]
Proved developed reserves:		
Crude oil (MBbls)	14,717	14,577
Natural Gas (MMcf)	417,362	248,634
NGL (MBbls)	15,958	12,856
Total proved developed reserves (MBoe)[(3)]	100,235	68,872
Proved undeveloped reserves:		
Crude oil (MBbls)	21,954	22,777
Natural Gas (MMcf)	499,262	368,382
NGL (MBbls)	19,589	17,300
Total proved undeveloped reserves (MBoe)[(3)]	124,753	101,474
Total proved reserves:		
Crude oil (MBbls)	36,671	37,354
Natural Gas (MMcf)	916,624	617,016
NGL (MBbls)	35,548	30,156

Total proved reserves (MBoe)[3][4]	224,989	170,346
Proved developed reserves (%)	45%	40%
Proved undeveloped reserves (%)	55%	60%
Reserve values (in thousands):		
Standardized measure of discounted future net cash flows	$ 1,081,193	$ 972,518
Discounted future income tax expense	$ 251,800	N/A
Total proved pre-tax PV-10[5]	$ 1,332,993	$ 972,518

(1) Our estimated reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $65.34 per Bbl for oil and $3.39 per MMBtu for natural gas at December 31, 2025. These base prices were adjusted for differentials on a per property basis, including local basis differentials and fuel costs, resulting in $58.61 per Bbl for oil, $2.77 per MMBtu for natural gas, and $23.20 per Bbl for NGLs at December 31, 2025.

(2) Our estimated reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $75.48 per Bbl for oil and $2.13 per MMBtu for natural gas at December 31, 2024. These base prices were adjusted for differentials on a per property basis, including local basis differentials and fuel costs, resulting in $67.98 per Bbl for oil, $1.42 per MMBtu for natural gas, and $25.48 per Bbl for NGLs at December 31, 2024.

(3) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(4) All proved reserves as of December 31, 2025 were part of a development plan adopted by management indicating that such locations were scheduled to be drilled within five years of initial classification.

(5) PV-10 is a non-GAAP financial measure and represents the estimated present value of the future cash flows less future development and production costs from our proved reserves before income taxes discounted using a 10% discount rate. PV-10 of proved reserves generally differs from the Standardized Measure (as defined herein), the most directly comparable GAAP financial measure, because it does not include the effects of future income taxes, as is required under GAAP in computing the Standardized Measure.

We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and natural gas companies. Because many factors that are unique to each individual company may impact the amount and timing of future income taxes, the use of PV-10 value provides greater comparability when evaluating oil and natural gas companies. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. However, the definition of PV-10 value as defined above may differ significantly from the definitions used by other companies to compute similar measures. As a result, the PV-10 value as defined may not be comparable to similar measures provided by other companies.

Investors should be cautioned that neither PV-10 nor Standardized Measure of proved reserves represents an estimate of the fair market value of our proved reserves. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities. See Note 19—"Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)" to our consolidated financial statements for additional information about the calculation of Standardized Measure.

Proved Undeveloped Reserves (in MBoe)

Our 2025 proved undeveloped reserves increased by approximately 23.3 MMBoe, or 23%, compared to 2024. The following reconciliation from 2024 to 2025 is presented to meet SEC requirements to provide material changes to our proved undeveloped reserves during the year. All of our PUDs are associated with drilling locations that are scheduled to be drilled within five years of the initial disclosure of proved reserves.

Proved undeveloped reserves at December 31, 2024	101,474
Conversions into proved developed reserves[1]	(30,691)
Revisions[2]	978
Extensions and discoveries[3]	52,992
Proved undeveloped reserves at December 31, 2025	124,753

(1) Conversions of PUD drilling locations in 2025 included developing 12 wells that were PUDs as of December 31, 2024.

(2) Total positive revisions of 978 MBoe were comprised of 3,930 MBoe of positive revisions related to increases in working interest, improvement in expense assumptions, and improvement in type curve, offset by downward revisions of 2,952 MBoe in PUDs from 2024 to 2025 due to 2 PUD locations that were removed due to changes to our development plan.

(3) Extensions primarily related to the addition of 28 PUD locations to be developed by 2030 (as that year entered the 5-year development window). These locations reside within the 5-year development window, which permits their recognition as PUD reserves based upon their continuing satisfaction of the engineering requirements for recognition as proved reserves. Extensions include the addition of new locations associated with our drilling program and additional Utica drilling in the 5-year development window.

Adjusted Index Prices Used in Reserve Calculations

The following tables show index prices used in our reserve calculations as of the dates indicated under historical SEC pricing:

Pricing Used for Proved Reserves as of December 31, 2025		
Based on Historical SEC Pricing:		
Oil (per Bbl)	$	58.61
Natural gas (per Mcf)	$	2.77
Natural gas liquids (per Bbl)	$	23.20
Pricing Used for Proved Reserves as of December 31, 2024		
Based on Historical SEC Pricing:		
Oil (per Bbl)	$	67.98
Natural gas (per Mcf)	$	1.42
Natural gas liquids (per Bbl)	$	25.48

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2025 and December 31, 2024 included in this Annual Report are based on reports prepared by Wright, our independent reserve engineer, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC in effect at such time. Copies of the reports are included as exhibits to this Annual Report. Wright provides a variety of services to the oil and gas industry, including field studies, oil and gas reserve estimations, appraisals of oil and gas properties and reserve report for their clients.

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. The technical and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, well-test data, production data (including flow rates), well data (including lateral lengths), historical price and cost information and property ownership interests. Our independent reserve engineer uses this technical data, together with standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy. The proved developed reserves and EURs are estimated using performance analysis and volumetric analysis. The estimates of the proved developed reserves and EURs are used to estimate the proved undeveloped reserves for each proved undeveloped location (utilizing type curves, statistical analysis, and analogy). Proved undeveloped drilling locations that are more than one offset from a proved developed well utilized reliable technologies to confirm reasonable certainty. The reliable technologies that were utilized in estimating these reserves include log data, performance data, log cross sections, seismic data, core data, and statistical analysis.

Internal Controls

Our internal staff of petroleum engineers works closely with Wright to ensure the integrity, accuracy and timeliness of data furnished to Wright. Periodically, our technical team meets with Wright to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Wright is an independent petroleum engineering and geological services firm.

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

For all of our properties, our internally prepared reserve estimates and the reserve report prepared by Wright are reviewed and approved by our SVP of Commercial and Production.

Qualifications of Responsible Technical Persons

Our SVP of Commercial & Production, Ryan Warner, is responsible for overseeing the preparation of the reserves estimates. Mr. Warner is a founding member at Infinity Natural Resources and has over 10 years of relevant experience in reservoir engineering and reserve estimation. He holds a degree in Petroleum Engineering from West Virginia University and is a registered Professional Engineer.

Wright was founded in 1988 by Mr. D. Randall Wright and performs consulting petroleum engineering services including but not limited to annual reserves audits, property evaluation, and reservoir analysis. Mr. Wright is the primary technical person in charge of the estimates of reserves and associated cash flow and economics on behalf of Wright for the results presented. He holds a Master of Science degree in Mechanical Engineering from Tennessee Technological University. He is a registered Professional Engineer in the state of Texas (TBPE #43291), granted in 1978, a member of the Society of Petroleum Engineers ("SPE") and a member of the Order of the Engineer.

Mr. Adam Null, a registered Professional Engineer in the State of Tennessee (TBAEE #122667), has provided technical assistance in the estimates of reserves and cash flow results presented. Mr. Null is a member of the SPE and has been practicing petroleum engineering for more than 10 years. He currently holds the title of Chief Operating Officer at Wright.

Mr. Wright and Mr. Null are qualified reserves evaluators as set forth in the "*Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information*" promulgated by the SPE. This qualification is based on years of practical experience in the estimation and evaluation of petroleum reserves.

Production, Revenue, Price and Production Costs

The following table sets forth information regarding our production, revenues and realized prices and production costs for the years ended December 31, 2025 and 2024. All of our production is derived from the Appalachian Basin. For additional information on price calculations, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,	
	2025	2024
Production data:		
Oil (MBbls)	3,074	2,380
Natural gas (MMcf)	45,596	28,291
NGL (MBbls)	2,209	1,723
Total (MBoe)(1)	12,882	8,818
Average daily production (MBoe/d)(1)	35.3	24.1
Average wellhead realized prices (before giving effect to realized derivatives):		
Oil (/Bbl)	$ 56.48	$ 67.86
Natural gas (/Mcf)	$ 2.80	$ 1.81
NGL (/Bbl)	$ 22.32	$ 26.14
Average wellhead realized prices (after giving effect to realized derivatives):		
Oil (/Bbl)	$ 60.98	$ 66.93
Natural gas (/Mcf)	$ 2.81	$ 2.47
NGL (/Bbl)	$ 22.22	$ 28.66
Operating costs and expenses (per Boe)(1):		
Gathering, processing and transportation	$ 4.25	$ 5.59
Lease operating	2.07	3.19
Production and ad valorem taxes	0.46	0.12
Depreciation, depletion, and amortization	8.05	8.36
General and administrative	11.91	1.48
Total	$ 26.74	$ 18.74

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

Productive Wells as of December 31, 2025

As of December 31, 2025, we owned interests in the following number of productive wells:

	Productive Wells	
	Gross	Net
Oil	152.0	104.7
Natural Gas	30.0	22.1
Total	182.0	126.8

Acreage as of December 31, 2025

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2025:

	Surface Acreage	
	Gross	Net
Undeveloped acres	55,989	53,532
Developed acres	48,141	44,887
Total	104,130	98,419

Undeveloped Acreage Expirations as of December 31, 2025

The following table sets forth the gross and net undeveloped acreage, as of December 31, 2025, that will expire over the next five years unless production is established within the spacing units covering the acreage, the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates or pursuant to other terms of the lease agreements. We expect to drill wells on such acreage or make extension payments prior to lease expiration.

	Acreage	
	Gross	Net
2026	71	71
2027	6,368	6,338
2028	1,588	1,543
2029	3,058	3,058
2030 and thereafter	1,424	1,423
	12,509	12,433

As of December 31, 2025, we had 28.1 MMBoe of proved undeveloped reserves that were associated with potentially expiring acreage.

Drilling Activity

The table below sets forth the results of our operated drilling activities for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	For the Year Ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	23.0	20.2	14.0	12.0	10.0	9.1
Dry Hole	—	—	—	—	—	—
Total Development Wells	23.0	20.2	14.0	12.0	10.0	9.1
Exploratory						
Productive	—	—	—	—	—	—
Dry Hole	—	—	—	—	—	—
Total Exploratory Wells	—	—	—	—	—	—

As of December 31, 2025, we had 8.0 gross (7.8 net) operated wells in process.

Major Customers

We generally sell our oil, natural gas and NGL production to purchasers at prevailing market prices, which in certain cases are adjusted for contractual differentials, and the majority of our revenue contracts have terms greater than twelve months.

We normally sell production to a relatively small number of customers, as is customary in our business. The table below summarizes the purchasers that accounted for 10% or more of our total net revenues for the periods presented:

	For the Year Ended December 31,	
	2025	2024
Marathon Oil Company	33%	55%
BP America	35%	17%
Ergon	16%	—%
Blue Racer Midstream	—%	10%

During these periods, no other purchaser accounted for 10% or more of our net revenues. As of December 31, 2025, the Company's accounts receivable balance related to oil and gas sales was comprised of amounts due from various purchasers, including amounts due from Marathon Oil Company, BP America and Ergon comprising 24%, 53%, and 18%, respectively, of the total balance. As of December 31, 2024, the Company's accounts receivable balance related to oil and gas sales was comprised of amounts due from Marathon Oil Company and BP America, which accounted for 49% and 25% respectively, of the total balance. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term. However, since crude oil and natural gas are fungible products with well-established markets and numerous purchasers and are based on current demand for oil and natural gas, we believe that the loss of any major purchaser would not have a material adverse effect on our financial condition or results of operations.

Title to Properties

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

Seasonality

Generally, demand for oil, natural gas and NGL decreases during the spring and fall months and increases during the summer and winter months. However, certain natural gas and NGL markets utilize storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. In addition, seasonal anomalies such as mild winters or mild summers can have a significant impact on prices. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages, increased costs or delay operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in evaluating and bidding for oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of developing natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Legislative and regulatory environment

Our oil, natural gas and NGL exploration, development, production and related operations and activities are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with such rules and regulations can result in administrative, civil or criminal penalties, compulsory remediation and imposition of natural resource damages or other liabilities. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, we believe these obligations generally do not impact us differently or to any greater or lesser extent than they affect other operators in the natural gas and oil industry with similar operations and types, quantities and locations of production.

Regulation of production

In most states, oil and natural gas companies are generally required to obtain permits for drilling operations, provide drilling bonds, file reports concerning operations and meet other requirements related to the exploration, development and production of oil, natural gas and NGLs. Such states also have statutes and regulations addressing conservation and reclamation matters, including provisions for unitization or pooling of natural gas and oil interests, rights and properties, the surface use and restoration of properties upon which wells are drilled and disposal of water produced or used in the drilling and completion process. These regulations include the establishment of maximum rates of production from natural gas and oil wells, rules as to the spacing, plugging and abandoning of such wells, restrictions on venting or flaring natural gas and requirements regarding the ratability of production, as well as rules governing the surface use and restoration of properties upon which wells are drilled.

These laws and regulations may limit the amount of oil, natural gas and NGLs that can be produced from wells in which we own an interest and may limit the number of wells, the locations in which wells can be drilled or the method of drilling wells. Additionally, the procedures that must be followed under these laws and regulations may result in delays in obtaining permits and approvals necessary for our operations and therefore our expected timing of drilling, completion and production may be negatively impacted. These regulations apply to us directly as the operator of our leasehold. The failure to comply with these rules and regulations can result in substantial penalties.

Regulation of sales and transportation of hydrocarbon liquids

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress has enacted price controls in the past and could reenact such controls in the future.

Our sales of oil and NGLs are affected by the availability, terms and cost of transportation. The transportation of oil, NGLs and other hydrocarbon liquids in common carrier pipelines is subject to rate and access regulation. FERC regulates the rates and terms and conditions of service of interstate transportation of oil, NGL and other liquids by pipeline under the Interstate Commerce Act. Typically, liquids pipelines’ interstate transportation rates are set using a generally applicable annual indexing methodology; however, a pipeline may also use a cost-of-service approach, set rates via settlement with shippers or utilize market-based rates in certain circumstances. The rates we pay for interstate transportation of liquids by pipeline, and the related terms of service, may change as a result of regulatory proceedings.

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

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 agencies of the U.S. federal government, primarily FERC and its predecessor agency. 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 uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act of 1978 ("NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation of natural gas in interstate commerce remains subject to extensive regulation primarily under the Natural Gas Act of 1938 ("NGA") and NGPA, pursuant to regulations and orders promulgated by FERC. The rates we pay for transportation of natural gas by pipeline, and related terms of service, may change as a result of regulatory proceedings. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected, directly or indirectly, by laws enacted by Congress and by FERC regulations.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical and financial sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC under the Energy Policy Act of 2005 (the "EPAct of 2005") and by the Commodity Futures Trading Commission ("CFTC") under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Act, and regulations promulgated thereunder. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity as well as certain disruptive trading practices. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

The EPAct of 2005 amended the NGA and NGPA to add an anti-market-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EPAct of 2005 also provided FERC with the power to assess civil penalties of up to $1,000,000 per day (adjusted annually for inflation) for violations of the NGA and NGPA. As of 2025, the new adjusted maximum penalty amount is $1,584,648 per violation, per day, in addition to disgorgement of profits associated with any violation. The civil penalty provisions are applicable to entities that engage in the sale and transportation of natural gas for resale in interstate commerce.

On January 19, 2006, FERC issued Order No. 670, implementing the anti-market-manipulation provision of the EPAct of 2005, and subsequently denied rehearing. The resulting rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to: (a) use or employ any device, scheme or artifice to defraud; (b) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (c) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-FERC jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services. FERC has also interpreted its authority to reach otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order No. 704, described below. However, in October 2022, the Fifth Circuit ruled that FERC's jurisdiction to regulate market manipulation and assess penalties is limited to interstate natural gas transactions only and does not reach intrastate natural gas transactions.

On December 26, 2007, FERC issued Order No. 704, a final rule on the annual natural gas transaction reporting requirements, as amended and clarified by subsequent orders on rehearing. As a result of these orders, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including oil and natural gas producers, gatherers and marketers, are now required to report, by May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance provided by FERC. Market participants must also indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transportation services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC. Although FERC has set forth a general test for determining whether natural gas facilities perform a non-jurisdictional gathering function or a jurisdictional transportation function, FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transportation facilities on which we transport our production as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. We believe that the natural gas pipelines in our own gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transportation services and federally unregulated gathering services could be the subject of litigation, changed regulations or interpretations thereof, and new or amended statutes or interpretations thereof, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational 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.

In addition, the pipelines in the gathering systems on which we rely may be subject to safety regulation by the U.S. Department of Transportation through its Pipeline and Hazardous Materials Safety Administration ("PHMSA"). PHMSA has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. Over the past several years, PHMSA has taken steps to expand the regulation of rural gathering lines and impose a number of reporting and inspection requirements on regulated pipelines, and additional requirements are expected in the future. On November 15, 2021, PHMSA released a final rule that expands the definition of regulated gathering pipelines and imposes safety measures on certain previously unregulated gathering pipelines. The final rule also imposes reporting requirements on all gathering pipelines and specifically requires operators to report safety information to PHMSA. We could incur significant costs or liabilities to comply with these PHMSA requirements or similar State safety requirements. Failure to comply with the applicable requirements could result in penalties or fines. As of January 2025, the maximum civil penalties PHMSA can impose are $272,926 per violation per day, with a maximum of $2,729,245 for a related series of violations. Furthermore, the future adoption of laws or regulations that apply more comprehensive or stringent safety standards could increase the expenses we incur.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. 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. 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.

Changes in law and to FERC, PHMSA, the CFTC, or state policies and regulations may adversely affect our own operations as well as the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines on which we transport natural gas. We cannot predict what future action FERC, PHMSA, CFTC, or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other oil and natural gas producers and marketers with which we compete.

Regulation of environmental and occupational safety and health matters generally

Our operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing environmental protection, occupational safety and health, and the release, discharge or disposal of materials into the environment, some of which carry substantial costs to maintain compliance and may impose substantial administrative, civil and criminal penalties for failure to comply. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response Compensation and Liability Act ("CERCLA"), the Clean Water Act ("CWA") and the federal Clean Air Act ("CAA"). In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the prevention and cleanup of pollutants and other matters. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit construction or drilling activities in sensitive areas such as wilderness, wetlands, frontier or other protected areas; require investigatory or remedial actions to prevent or mitigate pollution conditions caused by our operations; impose obligations to reclaim and abandon well sites and pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties, loss of leases, the imposition of investigatory or remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be feasible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. It is possible that, over time, environmental regulation could evolve to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or reinterpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities or waste handling, storage, transport, disposal or remediation requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot be certain that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our business, there can be no assurance that this will continue in the future.

The following is a summary of some of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

CERCLA, also known as the “Superfund” law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons known as potentially responsible parties, with respect to the release of “hazardous substances” into the environment. Potentially responsible parties include the current and past owners or operators of a disposal site or site where the release occurred and third parties who disposed or arranged for the disposal of the hazardous substances found at such sites. Under CERCLA, such persons may be subject to strict, joint and several and retroactive liability for the remediation of hazardous substances that have been released into the environment and for damages to natural resources. Neighboring landowners, governmental agencies, citizen organizations and other third parties may file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. We are only able to directly control the operation of those wells that we operate. The failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA and other environmental laws but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect our business operations. While petroleum and crude oil fractions are generally not considered hazardous substances under CERCLA and its analogues because of the so-called “petroleum exclusion,” adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

We also generate, handle, transport, store and dispose of solid and hazardous wastes that may be subject to the requirements of the Resource Conservation and Recovery Act, as amended (“RCRA”), and analogous state laws. RCRA regulates the generation, handling, storage, treatment, transport and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes “drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy” from regulation as hazardous wastes. With the approval of the Environmental Protection Agency (the “EPA”), individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent requirements. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain natural gas and oil exploration and production wastes as “hazardous wastes,” and potentially subject such wastes to much more stringent handling, disposal and clean-up requirements. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes are determined to have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease or operate numerous properties that may have been used by prior owners or operators for oil and natural gas development and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations where such substances have been taken for recycling or disposal. In addition, some of our properties may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and/or analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water discharges

The CWA, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other natural gas wastes, into or near waters of the United States or state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The discharge of dredge and fill material into regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the “Corps”). In April 2020 the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. Further, the U.S. Supreme Court’s decision issued in May 2023 in *Sackett v. EPA*, held that the jurisdiction of the CWA to regulate the waters of the United States (“WOTUS”) extends only to those adjacent wetlands that are indistinguishable from traditional navigable bodies of water due to a continuous surface connection. In September 2023, the EPA and the Corps published a direct-to-final rule redefining WOTUS to align with the decision in *Sackett*. However, roughly half of the states and other plaintiffs are continuing to challenge the 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 issued a proposed rule revising the definition of WOTUS with the stated aim of conforming to the U.S. Supreme Court’s decision in *Sackett* and revising certain regulatory terms, such as “relatively permanent,” “tributary,” and “continuous surface connection;” a final rule is expected in early 2026, and litigation is likely to follow issuance of the final rule. In addition, in an April 2020 decision further defining the scope of the CWA, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. The Court rejected the EPA and the Corps’ assertion that groundwater should be totally excluded from the CWA. 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 13, 2026, the EPA announced 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. To the extent a stay of recent rules or the implementation of a revised rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits, including for dredge and fill activities in wetland areas. Additionally, many states have similar requirements that apply to state waters where federal jurisdiction ends.

The process for obtaining permits also has the potential to delay our operations. For example, in January 2021, the Corps released the final version of a rule renewing twelve of its Nationwide Permits (“NWPs”), including NWP 12, the general permit issued by the Corps for pipelines and utility projects. The new rule, which took effect in March 2021, splits NWP 12 into three parts; NWP 12 will continue to be available to oil and gas pipelines. In March 2022, the Corps initiated an early review of NWP 12 to determine whether any future actions may be appropriate to modify NWP 12 prior to its expiration in 2026. However, in January 2025, President Trump issued an executive order instructing the Corps to use emergency authorities and NWPs to grant approvals for energy projects under Section 404 of the CWA, and on June 18, 2025, the Corps and the Department of Defense issued a proposed rule titled “Proposal to Reissue and Modify Nationwide Permits” to modify and clarify existing NWPs in order to authorize activities with no more and minimal adverse environmental effects. Any further changes to NWP 12 could have an impact on our business. We cannot predict at this time how the new Corps rule will be implemented because permits are issued by the local Corps district offices. If new oil and gas pipeline projects are unable to utilize NWP 12 or identify an alternate means of CWA compliance, such projects could be significantly delayed.

Additionally, spill prevention, control and countermeasure plans, also referred to as "SPCC plans," are required by federal law in connection with on-site storage of significant quantities of oil. Compliance may require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak.

Safe Drinking Water Act

The U.S. Safe Drinking Water Act ("SDWA") grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that presents an imminent and substantial endangerment to humans. The SDWA also regulates saltwater disposal wells under the Underground Injection Control Program. The federal EPAct of 2005 amended the Underground Injection Control provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of "underground injection," but disposal of hydraulic fracturing fluids and produced water or their injection for enhanced oil recovery is not excluded. In 2014, the EPA issued permitting guidance governing hydraulic fracturing with diesel fuels. While we do not currently use diesel fuels in our hydraulic fracturing fluids, we may become subject to federal permitting under SDWA if our fracturing formula changes or if there are other changes to the applicable provisions of the SDWA.

Air emissions

The CAA and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and other requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 parts per billion. Further, in June 2016, the EPA also finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. These rules could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These and other laws and regulations concerning air emissions may increase the costs of compliance for some facilities where we operate.

State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In March 2024, the EPA adopted new rules under the CAA that require the reduction of volatile organic compound ("VOC") and methane emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In addition, the regulations place new requirements to detect and repair volatile organic compound and methane at certain well sites and compressor stations. In December 2023, the EPA announced a final rule targeting methane emissions from new and existing oil and gas sources, 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 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. The final rule gives states, along with federal tribes, until March 2026 to develop and submit their plans for reducing methane emissions from existing sources, and those existing sources themselves have until 2029 from the plan submission deadline to comply. Fines and penalties for violation of the final rule could be substantial. The final rule is subject to ongoing litigation but remains in effect. 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. Further, in March 2025, the

EPA announced its intention to reconsider the March 2024 rule, with a final rule expected in or around July 2026. A subsequent rule finalized on November 26, 2025 also 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. Consequently, future implementation and enforcement of the final rule remains uncertain at this time. Several states, including West Virginia and Ohio, are considering their own regulations related to methane emissions from oil and gas operations. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas projects and increase our costs of development, which costs could be significant. Further, compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment and increased frequency of maintenance and repair activities to address emissions leakage at certain well sites and compressor stations, and also may require hiring additional personnel to support these activities or the engagement of third-party contractors to assist with and verify compliance.

Climate change

More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs") may be adopted and could cause us to incur material expenses to comply with such laws and regulations. These requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. The EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations.

At the international level, the Biden Administration signed the instrument recommitting the U.S. to the United Nations-sponsored Paris Agreement (the "Paris Agreement") in January 2021. However, in January 2025, President Trump issued executive orders 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. The withdrawal became effective in January 2026. On January 7, 2026, President Trump 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 uncertain at this time. At the same time, various state and local governments have committed to continue furthering the goals of the Paris Agreement and many of these initiatives are expected to continue.

Additionally, in 2022, the Inflation Reduction Act (the "IRA") was signed into law, which could accelerate the transition to a lower carbon economy. The IRA provides incentives for the development of renewable energy, clean hydrogen, clean fuels and supporting infrastructure and carbon capture and sequestration. In addition, the IRA includes a methane emissions reduction program that amends the Clean Air Act to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a "Waste Emissions Charge" on certain natural gas and oil sources that are already required to report under the EPA's Greenhouse Gas Reporting Program. To implement the program, in May 2024, EPA finalized revisions to the Greenhouse Gas Reporting Program for the oil and natural gas sector. The emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the Methane Emissions Reduction Program. However, in March 2025, President Trump signed Congress' Joint Resolution of Disapproval of the Waste Emissions Charge, and in May 2025 the EPA issued a final rule to remove the Waste Emissions Charge Regulations from the Code of Federal Regulations. In addition, in September 2025, the EPA proposed to permanently remove program obligations from the Greenhouse Gas Reporting Program for most source categories and suspect program obligations for some sources subject to subpart W (which applies to emissions sources in certain segments of the oil and natural gas industry) until 2034. The Inflation Reduction Act may also be subject to amendment or repeal through Congressional budget reconciliation. Consequently, future implementation and enforcement of these rules remains uncertain at this time. Additionally, some states have issued mandates to reduce emissions of GHGs, primarily through planned development of GHG emission inventories and potential cap-and-trade programs. Most of these types of programs require major sources of emissions or major producers of fuels to acquire and subsequently surrender emission allowances, with the number of allowances available being reduced each year until a target goal is achieved.

Further, in January 2024, the Biden Administration announced a temporary pause on pending decisions on exports of LNG to non-free trade agreement countries until the Department of Energy could update the underlying analyses for authorizations, including an assessment of the impact of GHG emissions. However, in January 2025, President Trump issued an executive order directing the Department of Energy to restart reviews of applications for approvals of LNG export projects as expeditiously as possible, and in April 2025 the Department of Energy rescinded its Policy Statement on Export Commencement Deadlines in Authorizations to Export Natural Gas to Non-Free Trade Agreement Countries, effectively ending the temporary pause on new exports of LNG. Separately, in April 2024, the European Union adopted a regulation to track and reduce methane emissions in the energy sector, including requiring new monitoring, reporting and verification measures to be applied by importers of oil, natural gas and coal into the European Union by January 1, 2027, and "maximum methane intensity values" must be met by 2030 and every year thereafter. Each member state will have the power to impose administrative penalties for failure to comply and the standard will be mandatory for supply contracts signed after the law takes effect. This and other changes in law and governmental policy may have impacts on our business that are difficult to anticipate.

The adoption and implementation of new or more stringent international, federal, state, or local legislation, regulations or other regulatory initiatives related to climate change or GHG emissions from oil and natural gas facilities could result in increased costs of compliance or costs of consumption, thereby reducing demand for our products, and could require us to incur increased operating costs or otherwise have an adverse effect on our business, financial condition and results of operations.

Hydraulic fracturing

Hydraulic fracturing is a common practice that is used to stimulate production of oil and/or natural gas from low permeability subsurface rock formations and is important to our business. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the hydrocarbon-bearing rock formation and stimulate production of hydrocarbons. We regularly use hydraulic fracturing as part of our operations. Presently, hydraulic fracturing is primarily regulated at the state level, but the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels.

In addition, there are heightened concerns by the public about hydraulic fracturing causing damage to aquifers, and there is potential for future regulation to address those concerns. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that certain activities associated with hydraulic fracturing may impact drinking water resources under some circumstances. To date, the EPA has taken no further action in response to the 2016 report.

At the state level, several states have adopted or are considering legal requirements that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. Local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Oil Pollution Act

The Oil Pollution Act of 1990 (the “OPA”) establishes strict liability for owners and operators of facilities that are the source of a release of oil into WOTUS. The OPA and its associated regulations impose a variety of requirements on responsible parties, including owners and operators of certain facilities from which oil is released, related to the prevention of oil spills and liability for damages resulting from such spills. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation or if the party fails to report a spill or to cooperate fully in the cleanup. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies to evaluate major federal actions having the potential to significantly impact the environment. The process involves the preparation of an environmental assessment and, if necessary, an environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action have the potential to significantly impact the environment. The NEPA process involves public input through comments, which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, may increase the costs of permitting and developing some facilities and could result, in certain instances, in the cancellation of existing leases. In July 2020, the Council on Environmental Quality ("CEQ") revised NEPA's implementing regulations to make the NEPA process more efficient, effective and timely. The rule required federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date (which was extended to two years in June 2021). In October 2021, CEQ issued a notice of proposed rulemaking to amend the NEPA regulatory changes adopted in 2020 in two phases. Phase I of the CEQ's rulemaking process was finalized on April 20, 2022, and generally restored provisions that were in effect prior to 2020. In May 2024, the CEQ finalized the Phase II rule that streamlined and clarified NEPA reviews while maintaining consideration of relevant environmental, climate change and environmental justice effects. The final rule took effect in July 2024. The Infrastructure and Investment Jobs Act, signed into law in November 2021, codified some of the July 2020 amendments. These amendments must be implemented into each agency's implementing regulations, and each of those individual rulemakings could be subject to legal challenge. Additionally, in June 2023, the Fiscal Responsibility Act of 2023 was signed into law, which includes important changes to NEPA to streamline the environmental review process. However, in February 2025, the U.S. District Court for the District of North Dakota vacated the Phase II rule, finding that NEPA does not authorize the CEQ to issue binding regulations. Also in February 2025, CEQ issued an interim final rule revoking the NEPA implementing regulations, and issued guidance recommending federal agencies revise their NEPA rules within one year, using CEQ's 2020 NEPA rules as a model and incorporating specific policy priorities. In January 2026, CEQ formally repealed its NEPA implementing regulations on the basis of the U.S. Supreme Court's decision in Seven County Infrastructure Coalition v. Eagle County, Colorado. In Seven County, the U.S. 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 full impact of these changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our operations and our ability to obtain governmental permits.

Endangered Species Act and Migratory Bird Treaty Act

The Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"). We may conduct operations on natural gas leases in areas where certain species that are or could be listed as threatened or endangered are known to exist. In February 2016, the U.S. Fish and Wildlife Service ("FWS") published a final policy which alters how it may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered 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 natural gas development. The Trump Administration issued rules that narrowed the definition of "habitat" and altered a policy in a way that made it easier to exclude territory from critical habitat. In October 2021, the Biden Administration published two rules that reversed those changes, and in June and July 2022, the FWS issued final rules rescinding former Trump-era regulations concerning the definition of "habitat" and critical habitat exclusions. In June 2023, the FWS issued three proposed rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. Final rules were published in April 2024, and took effect in May 2024. However, in January 2025, President Trump issued an executive order directing agencies to use, to the maximum extent permissible, the ESA regulation on consultations in emergencies to facilitate the domestic energy supply. The executive order also requires the quarterly convening of the Endangered Species Act Committee to ensure prompt and efficient review of all submissions for potential actions that could facilitate energy development. Further, in April 2024, the FWS and National Marine Fisheries Service proposed to redefine "harm" under the ESA to mean affirmative acts that are directed immediately and intentionally against a particular animal, excluding acts or omissions that indirectly cause injury. In addition, in November 2025, the Trump Administration proposed several rules that would significantly alter protections for plants and animals. One such proposed rule would rescind a rule that automatically extends protections for endangered species to threatened species. Another such proposed rule would change regulations for listing species as endangered or threatened as well as for designating critical habitats. A third such proposed rule would reinstate the framework for evaluating the benefits and costs of designating a critical habitat by considering factors such as economic impact, impact on national security, and other relevant impacts. The FWS is expected to issue final rules in 2026. As a result, future implementation and enforcement of these rules remains uncertain at this time. The designation of previously unprotected species as threatened or endangered or new critical or suitable habitat designations in areas where we conduct operations could result in limitations or prohibitions on our operations and could adversely impact our business. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

The Department of the Interior issued an opinion in December 2017, followed by a rule in January 2021 that narrows certain protections afforded to migratory birds pursuant to the MBTA. The MBTA makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests or eggs without a permit. The Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment to the Department of the Interior's plan to develop regulations that authorize incidental take under certain prescribed conditions. However, in April 2024, the U.S. Department of the Interior issued a memo, M-37085, which clarified that the MBTA only prohibits the intentional "take" of migratory birds. As a result, future implementation and enforcement of these rules under the MBTA remains uncertain at this time. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Worker health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, the purpose of which is to protect the health and safety of workers. For example, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we maintain, organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Related permits and authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related insurance

We maintain insurance against some contamination risks associated with our development activities, including a coverage policy for gradual pollution events. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Human Capital Resources

We aim to attract and retain top-tier talent in the oil and gas sector. As of December 31, 2025, we had 101 employees, none of whom were subject to a collective bargaining agreement.

We believe that our employees give us a sustainable competitive advantage, and we understand the need to attract, retain and develop the best team possible. We offer a variety of programs that are designed to retain our employees and also provide opportunities to grow their professional careers while continuing to deliver value to the Company. Additionally, we maintain a comprehensive suite of benefits that provide our employees with various options including retirement, health and wellness, and life and disability plans.

We are committed to a highly-qualified workforce, and we believe employees with different skill sets, experiences and interests drive superior results. We strive to promote a safe and healthy working environment, prioritizing the safety and well-being of our employees, contractors, the public and the environment in the communities where we operate.

Available Information

Our internet website address is www.infinitynaturalresources.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and related amendments, exhibits and other information, as soon as reasonably practicable after such materials are electronically filed with or furnished to the Securities and Exchange Commission (the "SEC"). You may also access and read our filings without charge through the SEC's website at www.sec.gov. Information contained on, or accessible through, our website shall not be deemed incorporated into and is not a part of this Annual Report.

ITEM 1A. RISK FACTORS

Investing in our Class A common stock involves risks. You should carefully consider the following risks and uncertainties, as well as the other information contained in this Annual Report, including those described in "Cautionary Statement Regarding Forward-Looking Statements." The risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. The occurrence of any of the following risks or additional risks and uncertainties that are currently immaterial or unknown could materially and adversely affect our business, financial condition, liquidity, results of operations and cash flows. The trading price of our Class A common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to Commodity Prices

Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition and results of operations, liquidity and our ability to meet our financial commitments or cause us to delay our planned capital expenditures.

Our revenues, operating results, profitability, liquidity and ability to grow depend primarily upon the prices we receive for the oil, natural gas and NGLs we sell. We require substantial expenditures to replace our oil, natural gas and NGL reserves, sustain production and fund our business plans, including our development and exploratory drilling efforts. Lower commodity prices negatively affect the amount of cash available for capital expenditures, could negatively affect our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our business, prospects, financial condition, results of operations and cash flows. In addition, low prices may reduce the quantities of oil, natural gas and NGL reserves that may be economically produced and result in an impairment of our natural gas and oil properties.

Historically, the markets for oil, natural gas and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil, natural gas and NGL prices may result from relatively minor changes in the supply of or demand for oil, natural gas and NGLs, market uncertainty and other factors that are beyond our control, including:

- worldwide and regional economic conditions impacting the supply and demand for oil, natural gas and NGLs, including inflationary pressures;
- changes in seasonal temperatures, including the number of heating degree days during winter months and cooling degree days during summer months;
- the level of oil, natural gas and NGL exploration, development and production;
- the level of U.S. LNG exports;
- prevailing prices on local price indexes in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- the spot price of LNG on world markets;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- speculative trading in natural gas derivative contracts;
- armed conflict, political instability or civil unrest in oil and gas producing regions, including armed conflict and instability in the Middle East, Venezuela, Mexico and the conflict between Russia and Ukraine, and the related potential effects on laws and regulations or the imposition of economic or trade sanctions;

- the occurrence or threat of epidemic or pandemic diseases, or any government response to such occurrence or threat;
- political and economic conditions in or affecting major LNG consumption regions or countries, particularly Asia and Europe;
- actions of the Organization of the Petroleum Exporting Countries ("OPEC"), including the ability and willingness of the members of OPEC and other exporting nations to agree to and maintain oil price and production controls, including the anticipated increases in supply from Russia and OPEC, particularly Saudi Arabia;
- U.S. trade policies and their effect on U.S. oil, natural gas and NGL exports;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

Lower commodity prices may reduce our operating margins, cash flow and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves or make acquisitions could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with natural gas prices at levels lower than current Henry Hub strip prices or oil prices lower than current WTI strip prices may adversely affect our drilling economics, cash flow and our ability to raise capital, which may require us to re-evaluate and postpone or substantially restrict our development program and result in the reduction of some of our proved undeveloped reserves and related PV-10. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to meet our financial commitments or cause us to delay our planned capital expenditures.

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

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices and drilling activity in our areas of operation and other major shale basins throughout the U.S. These cost increases result from a variety of factors beyond our control, such as increases in the cost of sand and other proppant used in hydraulic fracturing operations; steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities. Furthermore, high oil prices have historically led to more development activity in oil-focused shale basins and resulted in service cost inflation across all U.S. shale basins, including our areas of operation. Higher levels of development activity in oil-focused shale basins have also historically resulted in higher levels of associated gas production that places downward pressure on natural gas prices. To the extent natural gas prices decline due to a period of increased associated gas production and we experience service cost inflation during such period, our cash flow and profitability may be materially adversely impacted.

Certain factors could require us to write down the carrying values of our properties, including commodity prices decreasing to a level such that our future undiscounted cash flows from our properties are less than their carrying value.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, drilling and completion results, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash impairment charge to earnings. Lower commodity prices in the future could result in impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. For example, natural gas prices are a critical component to our fair value estimate of our natural gas properties. If these prices decline, we will record an impairment, which is a non-cash charge to earnings, if we determine that an asset's carrying value exceeds its estimated fair value. Impairment expense may have a material adverse effect on our earnings. We could experience further material write-downs as a result of other factors, including low production results or high lease operating expenses, capital expenditures or transportation fees.

Risks Related to Our Reserves, Leases and Drilling Locations

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil, natural gas and NGL reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. In order to prepare reserve estimates, production rates and timing of development expenditures must be projected and available geological, geophysical, production and engineering data must be analyzed. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as commodity prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, commodity prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable reserves may vary materially from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected and production declines may be greater than we estimate and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates of proved reserves to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves. Furthermore, our development plan calls for completing horizontal wells using tighter frac spacing and substantially higher proppant volumes, which may increase the risk that these wells interfere with production from existing or future wells in the same spacing section and horizon, which in turn may result in lower recoverable reserves. There can be no assurance that our reserves will ultimately be produced.

You should not assume that the present values of future net cash flows from our reserves presented in this Annual Report are the current market value of our estimated reserves. Actual future prices and costs may differ materially from those used in our present value estimates using SEC pricing. If spot prices or future actual prices are below the prices used in our current reserve estimates, using those prices in estimating proved reserves may result in a decrease in proved reserve volumes due to economic limits. You should not assume that the PV-10 values of our estimated reserves are accurate estimates of the current fair value of our estimated oil, natural gas and NGL reserves.

Unless we replace our reserves with new reserves and develop those new reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

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

As of December 31, 2025, approximately 55% of our total estimated proved reserves were classified as proved undeveloped under SEC pricing. Estimated net future development costs relating to the development of our PDNPs and PUDs at December 31, 2025 are approximately $737 million over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. We plan to fund our capital development program primarily through cash flow from our operations. Our ability to fund these expenditures is subject to a number of risks. For additional information, see "—Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves." Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the PV-10 value of our estimated PUDs and future net cash flows 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 some of our PUDs as unproved reserves. Furthermore, there is no certainty that we will be able to convert our PUDs to developed reserves or that our undeveloped reserves will be economically viable or technically feasible to produce.

Further, SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. As a result, we may be required to reclassify certain of our PUDs if we do not drill those wells within the required five-year timeframe.

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

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Although approximately 87% of our acreage is HBP, held by operations or held-by-storage as of December 31, 2025, the remaining acreage is subject to expiration over future years. Of the remaining 13% of our acreage not HBP, approximately 1% will be subject to expiration in 2026, 51% in 2027 and approximately 48% thereafter, although a portion of our leases generally grant us the right to extend these leases for an additional three or five-year period. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties. The cost to renew expiring leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. If we are unable to fund renewals of expiring leases, we could lose portions of our acreage and our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled certain drilling locations as an estimation of our future multiyear drilling activities on our existing acreage. Our identified drilling locations represent locations to which proved, probable or possible reserves were attributable. Our ability to drill and develop these locations depends on a number of uncertainties, including commodity prices, statutory unitization, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, availability and cost of sand and other proppant used in hydraulic fracturing operations, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, access to and availability of saltwater disposal systems, regulatory approvals, the cooperation of other working interest owners and other factors. Because of these uncertain factors, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. Further, certain of the horizontal wells we intend to drill in the future may require pooling or unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to pool or unitize such leaseholds with ours, the total locations we can drill may be limited. As such, our actual drilling activities may materially differ from those presently identified. For more information on our future potential acreage expirations, see “Item 1. Business and Properties—Our Properties— Undeveloped Acreage Expirations as of December 31, 2025.”

Although we plan to fund our drilling program primarily with cash flow from operations, if our cash flows are less than we expect or we change our drilling activities, we may be required to borrow under our Credit Facility or issue debt or equity securities in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. For additional information, see “—Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.” Any drilling activities we are able to conduct on these locations may not be successful, may not result in production or additions to our estimated proved reserves and could result in a downward revision of our estimated proved reserves, which could have a material adverse effect on the borrowing base under our

Credit Facility or our future business and results of operations. Additionally, if we curtail our drilling program, we may be required to reduce our estimated proved reserves, which could reduce the borrowing base under our Credit Facility.

Properties that we decide to drill may not yield oil, natural gas and NGLs in commercially viable quantities.

Although we believe that the vast majority of our drilling locations are technically proved, any inability to develop commercially viable quantities will adversely affect our results of operations and financial condition. Properties that we decide to drill that do not yield natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil, natural gas or NGLs in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of geologic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Seismic data is subject to interpretation and may not accurately identify the presence of drilling hazards, which could adversely affect the results of our drilling operations.

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

Risks Related to Our Operations

We may be unable to integrate the recently acquired Antero Ohio Assets successfully, or realize the anticipated benefits of the acquisition.

Our ability to achieve the anticipated benefits of the recently completed acquisition of the Antero Ohio Assets will depend in part upon whether we can integrate the assets into our existing business in an efficient and effective manner, including aligning development plans, operating practices, cost structures, data systems, and regulatory compliance processes. We may not be able to accomplish this integration process successfully. The integration process may be subject to delays or changed circumstances, and we can give no assurance that our expectations with respect to integration or cost savings as a result of the acquisition will materialize or that the Antero Ohio Assets will perform in accordance with our expectations. The success of the acquisition will depend, in significant part, on the Company's ability to successfully integrate the acquired business, grow the revenue of the Company and realize the anticipated strategic benefits from the acquisition. Additionally, the integration process may result in the disruption of ongoing business and there could be potential unknown liabilities and unforeseen expenses associated with the acquisition that were not discovered in the course of performing customary due diligence. The integration may also require significant time and focus from management following the acquisition which may disrupt the Company's business and results of operations. Our failure to achieve consolidation savings, to successfully integrate the Antero Ohio Assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

We and Northern jointly own the Antero Ohio Assets pursuant to an undivided interest acquisition structure and are subject to a cooperation agreement, infrastructure joint ownership agreement and joint operating agreement with Northern. Disagreements or misalignment with our partner could adversely affect development plans, capital allocation, or timing of returns.

Pursuant to a cooperation agreement, infrastructure joint ownership agreement and joint operating agreement, we co-won an undivided interest in the Antero Ohio Assets with Northern, but we operate the assets. Conflicts of interest are not anticipated but may arise in the future with Northern, where its business interests are inconsistent with our and our stockholders' interests. Further, disagreements or disputes with Northern, while not expected, could result in litigation, resulting in increase of expenses incurred and potentially limit the time and effort our officers and directors are able to devote to remaining aspects of our business, all of which could have a material adverse effect on our business, financial condition and results of operations, including our development plans, capital allocation, or timing of returns. This arrangement may also limit the price or interest level for our interests in the Antero Ohio Assets, in the event we want to sell such interests.

Notwithstanding the due diligence investigation that we performed in connection with our entry into the definitive agreement to purchase the Antero Ohio Assets, the Antero Ohio Assets may have liabilities, losses or other exposures for which we do not have adequate insurance coverage or other protection.

While we performed due diligence on the Antero Ohio Assets prior to our entry into the definitive agreement to purchase the Antero Ohio Assets, we are dependent on the accuracy and completeness of statements and disclosures made or actions taken by the Upstream Sellers and Midstream Sellers and their representatives when conducting due diligence and evaluating the results of such due diligence. We do not control and may be unaware of activities of the Upstream Sellers and Midstream Sellers prior to the completion of the Antero Acquisition, including intellectual property and other litigation, claims or disputes, information security vulnerabilities, violations of laws, policies, rules and regulations, commercial disputes, tax liabilities and other known and unknown liabilities.

With the consummation of the Antero Acquisition, certain of the liabilities of the Antero Ohio Assets, including contingent liabilities, will be consolidated with our liabilities for purposes of financial reporting. The Antero Ohio Assets may have unknown liabilities that we will be responsible for following the consummation of the Antero Acquisition. If those liabilities are greater than expected, or if there are obligations of the Antero Ohio Assets of which we are not aware, our business could be materially and adversely affected. We do not have indemnification rights from the Upstream Sellers and Midstream Sellers for defects and liabilities associated with the acquired assets and instead will rely on a limited representation and warranty insurance policy, which we have obtained. Such insurance is subject to exclusions, policy limits and certain other customary terms and conditions. If we are responsible for liabilities not covered by our representation and warranty insurance policy, we could suffer consequences that could have a material adverse effect on our financial condition and results of operations.

Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

The oil and gas industry is capital-intensive. Although we expect to fund our capital budget primarily with cash flow from our operations, a number of factors could cause our cash flow to be less than we expect, including the results of our drilling and completion program. Moreover, our capital budgets are based on a number of assumptions, including drilling and completion costs, midstream service costs, commodity prices and drilling results, and are therefore subject to change. If our cash flows are less than we expect, we decide to pursue acquisitions or we change our capital budgets, we may be required to borrow under our Credit Facility or issue debt or equity securities to consummate such acquisitions or fund our drilling and completion program. The incurrence of additional indebtedness, either through borrowings under our Credit Facility, the issuance of debt securities or otherwise, would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund capital expenditures and acquisitions. The issuance of additional equity securities would be dilutive to our other stockholders. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things: commodity prices; actual drilling results; the availability and cost of drilling rigs and other services and equipment; the availability, cost and adequacy of midstream gathering, processing, compression and transportation infrastructure; and regulatory, technological and competitive developments.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- the amount of our proved reserves;
- the amount of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the amount of our operating expenses;
- cash settlements from our derivative activities;
- our ability to borrow under our Credit Facility; and
- our ability to access the capital markets or sell non-core assets.

If our revenues or the borrowing base under our Credit Facility decrease as a result of lower commodity prices, operational difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to make acquisitions or sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our Credit Facility are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of the development of our properties, which in turn could lead to a decline in our reserves and production and could materially and adversely affect our business, financial condition and results of operations.

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

Our future financial condition and results of operations will depend on the success of our development, production and acquisition activities, which are subject to numerous risks beyond our control. For example, we cannot assure you that wells we drill will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil, natural gas and NGLs often involves unprofitable efforts from wells that do not produce sufficient oil, natural gas and NGLs to return a profit at then-realized prices after deducting drilling, operating and other costs. In addition, our cost of drilling, completing and operating wells is often uncertain.

Our decisions to develop or purchase prospects or properties will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.”

Further, many factors may increase the cost of, curtail, delay or cancel our scheduled drilling projects, including:

- declines in oil, natural gas and NGL prices;
- increases in the cost of, and shortages or delays in the availability of, proppant, equipment, services and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- capacity or pressure limitations on gathering systems, processing and treating facilities or other related midstream infrastructure;
- coal and other mineral ownership permitting issues may impact our ability to develop on our current timeline;
- drilling in the vicinity of coal mining operations and certain other structures;
- any future lack of available capacity on interconnecting transmission pipelines;
- complying with regulatory requirements, including limitations on freshwater sourcing, wastewater disposal, emission of GHGs and hydraulic fracturing;
- pressure or irregularities in geological formations;
- limited availability of financing on acceptable terms;
- compliance with or liability arising under environmental laws and regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the environment;
- compliance with contractual requirements;
- competition for surface locations from other operators that may own rights to drill at certain depths across portions of our leasehold;
- adverse weather conditions;
- title issues or legal disputes regarding leasehold rights; and
- other market limitations in our industry.

Some of our properties are in areas that may have been partially depleted or drained by offset (i.e., neighboring) wells, and certain of our wells may be adversely affected by actions other operators may take when drilling, completing or operating wells that they own.

Some of our properties are in areas that may have been partially depleted or drained by earlier drilled offset wells. We have no control over offsetting operators who could take actions such as drilling and completing nearby wells, which actions could adversely affect our operations. When a new offset well is completed and produced, reserves previously attributed to offset wells may be produced by the new well which could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. The possibility for these impacts may increase with respect to wells that are shut in as a response to lower commodity prices or the lack of pipeline and storage capacity. In addition, completion operations and other activities conducted on other nearby wells could cause us, in order to protect our existing wells, to shut in production for indefinite periods of time. Shutting in our wells and damage to our wells from offset completions could result in increased costs and could adversely affect the reserves and re-commenced production from such shut in wells as well as the timing of cash flows from impacted wells.

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from oil and gas wells and the unitization or pooling of oil and gas properties. Some states allow the forced pooling or unitization of tracts to facilitate exploration and development, while other states rely on voluntary pooling of lands and leases. Such rules often impact the ultimate timing of our exploration and development plans. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

Part of our business strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques, which include drilling longer laterals and completing wells with larger fluid volumes and higher proppant volumes. The difficulties we face drilling horizontal wells include:

- landing our wellbores in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore;
- potentials for casing failures; and
- being able to run and remove tools and other equipment consistently through the entire length of the wellbore.

Difficulties that we face while completing our wells include:

- the ability to fracture stimulate the planned number of stages with the planned amount of fluid and proppant;
- the ability to run tools through the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, our development plan calls for completing horizontal wells using greater fluid volumes and substantially higher proppant volumes in addition to drilling additional and longer laterals off of existing well pads, which may increase the risk that these wells interfere with production from existing or future wells in the same spacing section and horizon. This may cause such wells to produce at lower rates than we anticipate and produce lower recoverable reserves. These latest drilling and completion techniques require substantially more capital on a per well basis (when compared to vertical wells), which may result in us drilling and completing fewer wells per year. If our development and production results are less than anticipated, the return on our investment for a particular well or region may not be as attractive as we anticipated, and we could incur material write-downs of our undeveloped acreage, and its value could decline in the future.

Our ability to produce oil, natural gas and NGLs economically and in commercial quantities is dependent on the availability of adequate supplies of water for drilling and completion operations and access to water and waste disposal or recycling facilities and services at a reasonable cost. Restrictions on our ability to obtain water or dispose of produced water and other waste may have an adverse effect on our financial condition, results of operations and cash flows.

The hydraulic fracturing stimulation process on which we depend to produce commercial quantities of oil, natural gas and NGLs requires the use and disposal of significant quantities of water. The availability of water recycling facilities and other disposal alternatives to receive all of the water produced from our wells may affect our production. Our inability to secure sufficient amounts of water, to dispose of or recycle the water used in our operations or to timely obtain water sourcing permits or other rights could adversely impact our operations. The availability of water may change over time in ways that we cannot control, including as a result of shifting weather patterns. Additionally, the imposition of new environmental initiatives and regulations could include restrictions on our ability to obtain water or dispose of waste and adversely affect our business and operating results.

Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin in eastern Ohio and southwestern Pennsylvania. As of December 31, 2025, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by, and costs associated with, governmental regulation, state and local political activities, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

The marketability of certain of our production is dependent upon transportation and other facilities, which we do not control. If these facilities are unavailable, or if there are any increases in the cost of using these services or facilities, our operations could be interrupted, our revenues could be reduced and our costs could increase.

The marketability of certain of our oil, natural gas and NGLs production depends in part upon the availability, proximity and capacity of transportation pipelines, plants and other midstream facilities, which are owned by third parties. Certain of our natural gas production is collected from the wellhead by third-party gathering lines and transported to gas processing or treating facilities and/or transmission pipelines. Our oil and NGLs production in some cases are also dependent on certain midstream infrastructure. We do not control these third-party facilities and our access to them may be limited, curtailed or denied. Economic, regulatory or other issues may affect the construction and availability of needed third-party facilities. These pipelines, plants, and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements, and curtailments of receipts or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. These third-party facilities may experience unplanned downtime or maintenance for a variety of reasons outside our control, and our production could be materially negatively impacted as a result of such outages. Insufficient production from our wells to support the construction of pipeline facilities by third parties or a significant disruption in the availability of third-party midstream facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, natural gas and NGLs and thereby cause a significant interruption in our operations.

If, in the future, we are unable, for any sustained period, to implement gathering, treating, processing, fractionation or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations. Additionally, certain of our gas gathering arrangements are subject to cost-of-service fee arrangements. The variable nature of these fee arrangements may result in per unit cost increases over time. If such increases occur, our costs could rise, which would negatively impact our financial results.

The unavailability or high cost of drilling rigs, completion crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, completion crews, pipe and other equipment and supplies, including sand and other proppant used in hydraulic fracturing operations, as well as for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in our industry, can fluctuate significantly, often in correlation with inflationary pressures, commodity prices or drilling activity in our areas of operation and in other shale basins in the U.S., causing periodic shortages of supplies and needed personnel and rapid increases in costs. Increased drilling activity could materially increase the demand for and prices of these goods and services, and we could encounter rising costs and delays in or an inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to conduct our drilling and development activities, which could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs could have a material adverse effect on our cash flow and profitability.

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

The largest purchaser of our oil and natural gas during the year ended December 31, 2025, accounted for approximately 35% of our total oil, natural gas and NGL revenues. As is typical in our industry, this purchaser's contract is short-term in nature and is renewed in six-month increments. While we are not substantially dependent on this purchaser's contract and we believe that we could find replacement purchasers of our oil and natural gas on acceptable terms if any one or more of the significant purchasers were unable to satisfy their contractual obligations, there can be no assurance that we will be able to do so on terms that we consider acceptable or at all. To the extent we are unable to replace such purchasers, it would adversely affect our business, financial condition, results of operations and cash flows. Further, the inability of one or more of our customers to pay amounts owed to us could adversely affect our business, financial condition, results of operations and cash flows.

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

The existence of a material title deficiency can render a lease worthless and adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of completed acquisitions will depend on our ability to effectively integrate the acquired businesses into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our Credit Facility imposes certain limitations on our ability to enter into mergers or combination transactions and to incur certain indebtedness, which could indirectly limit our ability to acquire assets and businesses. For additional information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Financing Agreements—Credit Facility."

Future legislation or changes in tax laws and regulations may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction, transportation and sales.

We are subject to taxation by various governmental authorities at the federal, state and local levels in the jurisdictions in which we operate. New legislation could be enacted by these governmental authorities, which could increase our tax burden and increase the cost to produce oil, natural gas or NGLs. Members of Congress periodically introduce legislation to revise U.S. federal income tax laws which could have a material impact on us. In the past, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal and state income tax laws, including to certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Future adverse changes could include, but are not limited to, (a) the repeal of the percentage depletion allowance for oil and natural gas properties, (b) the elimination of current deductions for intangible drilling and development costs, and (c) an extension of the amortization period for certain geological and geophysical expenditures. In addition, federal or state legislation increasing the amount of tax imposed on oil and natural gas extraction, transportation or sales could also be enacted. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or other similar changes to federal or state income tax laws could eliminate or postpone certain tax deductions or credits that are currently available with respect to oil and natural gas exploration and development, which could result in increased operating costs and negatively affect our financial condition, results of operations and cash flows. Additionally, state and local taxing authorities in jurisdictions in which we operate or own assets may enact new taxes, such as the imposition of a severance tax on the extraction of natural resources in states in which we produce natural gas, NGLs and oil or change the rates of existing taxes, which could adversely impact our earnings, cash flows and financial position.

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

Any changes in our effective tax rates or tax liabilities could adversely affect our results of operations and financial condition. 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;
- expansion into or future activities in new jurisdictions;
- the availability of tax deductions, credits, exemptions, refunds and other benefits to reduce tax liabilities;
- tax effects of share-based compensation; and
- changes in tax laws, tax regulations, accounting principles, or interpretations or applications thereof.

In addition, we are also subject to the examination of our tax returns by the U.S. Internal Revenue Service (the "IRS") and other tax authorities. An adverse outcome arising from an examination of our income or other tax returns could result in higher tax exposure, penalties, interest or other liabilities that could have an adverse effect on our operating results and financial condition. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for income taxes. Although we believe our tax provisions are adequate, the final determination of tax audits and any related disputes could be materially different from our historical income tax provisions and accruals. The results of audits or related disputes could have an adverse effect on our financial statements for the period or periods for which the applicable final determinations are made.

Continuing or worsening inflationary pressures and associated changes in monetary policy may result in increases to the cost of our goods, services, and personnel, which in turn could cause our capital expenditures and operating costs to rise.

Inflation has been an ongoing concern in the U.S. since 2021. Ongoing inflationary pressures may result in increases to the costs of our oilfield goods, services and personnel, which would, in turn, cause our capital expenditures and operating costs to rise. Sustained levels of high inflation could cause the U.S. Federal Reserve and other central banks to increase interest rates, which could 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 and impact our ability to raise capital.

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

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

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

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

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring natural gas or oil properties requires us to assess recoverable reserves; future oil, natural gas and NGL prices and their applicable differentials; development and operating costs and potential liabilities, including environmental liabilities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such assessments are inexact and inherently uncertain. For these reasons, the properties we have acquired or will acquire in the future may not produce as expected or may not be accretive to free cash flow. In connection with the assessments, we perform a review of the subject properties, but such a review may not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental concerns, such as any groundwater contamination or pipe corrosion, when a review is performed. We may be unable to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are subject to risk and uncertainties, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition.

Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce superior rates of return. In developing our business plan, we consider allocating capital and other resources to various aspects of our businesses, including well development, reserve acquisitions, exploratory activity, corporate items (including share and debt repurchases) and other alternatives, including investments into new proprietary technologies and strategies surrounding the generation and monetization of environmental attributes from our operations, including but not limited to carbon credit offsets. We also consider likely sources of capital, including cash generated from operations and borrowings under our Credit Facility. Notwithstanding the determinations made in the development of our core business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions and opportunities to monetize technological improvements to our operations.

If we fail to identify optimal business strategies, optimize our capital investment and capital raising opportunities, use our other resources in furtherance of our business strategies, make appropriate capital investment decisions or anticipate regulatory, policy and market changes associated with any of our strategic determinations, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We maintain insurance against some, but not all, operating risks and losses. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our development activities are subject to all of the operating risks associated with drilling for and producing oil, natural gas and NGLs, including, but not limited to, the possibility of:

- environmental hazards, such as unplanned releases of pollution into the environment, including soil, groundwater and air contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

Any of these events could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties; and
- repair and remediation costs.

We may elect not to obtain insurance for certain of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, risks related to pollution and the environment are generally not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition or results of operations.

Competition in our industry is intense, making it more difficult for us to acquire properties, market oil, natural gas and NGLs, secure trained personnel and raise additional capital.

Our ability to acquire additional oil and gas properties and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil, natural gas and NGLs and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Many of our competitors possess and employ greater financial, technical and personnel resources than we do. Those companies may be able to pay more for natural gas and oil properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring natural gas and oil properties, developing reserves, marketing our production, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, geologic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, natural gas and NGLs, costs associated with incident response or lost employee time and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Cyberattacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cybersecurity threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized access to our seismic data, reserves information, customer or employee data or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operations. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyberattack involving our information systems and related infrastructure, or that of our business associates, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer's, supplier's or royalty owners' data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

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

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

Terrorist attacks, including eco-terrorism, the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could affect the energy industry, the environment and industry related economic conditions, including our operations, the operations of our customers, as well as general economic conditions, consumer confidence, spending and market liquidity. Strategic targets, including energy-related assets, may be at greater risk of future attacks than other targets in the United States. The occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially adversely affect our business and results of operations.

A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity, financial condition, results of operations, cash flows and ability to pay dividends on our Class A common stock.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the European, Asian and the U.S. financial markets have contributed to economic volatility and diminished expectations for the global economy. Historically, concerns about global economic growth have had a significant impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and materially adversely impact our results of operations, liquidity, financial condition, results of operations, cash flows and ability to pay dividends on our Class A common stock.

We previously identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future which, if not corrected, could affect the reliability of our consolidated financial statements and have other adverse consequences.

As more fully disclosed in this Annual Report under "Item 9A. Controls and Procedures," we evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2025. Based on that evaluation, we concluded that our disclosure controls and procedures were ineffective as of December 31, 2025 due to material weaknesses identified in our internal control over financial reporting.

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis.

We have identified material weaknesses in our internal control over financial reporting which relate to: (a) our general segregation of duties, including the review and approval of journal entries; (b) the lack of a formalized risk assessment process; (c) identification and implementation of control activities, including over information technology; (d) identification and application of a sufficient level of formal accounting policies and procedures; and (e) maintaining a sufficient complement of accounting and financial reporting resources commensurate with our financial reporting requirements.

Our management has concluded that these material weaknesses in our internal control over financial reporting are due to the fact that we previously operated as a private company with limited resources and have not had the necessary business processes and related internal controls formally designed and implemented coupled with the appropriate resources with the appropriate level of experience and technical expertise to oversee our business processes and controls.

Our management is in the process of implementing a remediation plan. The material weaknesses will be considered remediated when our management designs and implements effective controls that operate for a sufficient period of time and management has concluded, through testing, that these controls are effective. Our management will monitor the effectiveness of its remediation plans and will make changes management determines to be appropriate. As of December 31, 2025, these material weaknesses have not yet been remediated.

If not remediated, these material weaknesses could result in material misstatements to our annual or interim consolidated financial statements that might not be prevented or detected on a timely basis, or in delayed filing of required periodic reports. We cannot assure you that the measures we have taken to date, or any measures we may take in the future, will be sufficient to remediate the control deficiencies that led to the material weaknesses in our internal control over financial reporting described above or to avoid potential future material weaknesses. In addition, our independent registered public accounting firm has not ever performed an evaluation of our internal control over financial reporting in accordance with the provisions of the Sarbanes-Oxley Act because no such evaluation has been required. Had our independent registered public accounting firm performed an evaluation of our internal control over financial reporting in accordance with the provisions of the Sarbanes-Oxley Act, additional material weaknesses may have been identified. When required in the future, if our independent registered public accounting firm is unable to express an unqualified opinion as to the effectiveness of the internal control over financial reporting, investors may lose confidence in the accuracy and completeness of our financial reports, the market price of the our Class A common stock could be adversely affected and we could become subject to litigation or investigations by the NYSE, the SEC, or other regulatory authorities, which could require additional financial and management resources.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we are unable to successfully remediate our existing or any future material weakness in our internal control over financial reporting, or identify any additional material weaknesses that may exist, the accuracy and timing of our financial reporting may be adversely affected, we may be unable to maintain compliance with securities laws requirements regarding timely filing of periodic reports in addition to applicable stock exchange listing requirements, we may be unable to prevent fraud, investors may lose confidence in our financial reporting, and our stock price may decline as a result. Additionally, our reporting obligations as a public company could place a significant strain on our management, operational and financial resources and systems for the foreseeable future and may cause us to fail to timely achieve and maintain the adequacy of our internal control over financial reporting.

Risks Related to Our Derivative Transactions, Debt and Access to Capital

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGLs, we enter into derivative contracts for a significant portion of our projected oil, natural gas and NGL production, primarily consisting of swaps. For additional information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Cash Flow Activity—Derivative Activities." Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received for the sale of our production; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties and oil, natural gas and NGL prices.

The cost to drill and complete our wells often increases in times of rising commodity prices. To the extent our drilling and completion costs increase but our derivative arrangements limit the benefit we receive from increases in commodity prices, our margins could be limited, which could have a material adverse effect on our financial condition. In addition, the amount we pay in production taxes is calculated without taking our derivative arrangements into account, and if our derivative arrangements limit the benefit we receive from increases in commodity prices, the effective tax rate we pay in production taxes could increase.

Our derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions would generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our derivative contracts.

The failure of our hedge counterparties, significant customers or working interest holders to meet their obligations to us may adversely affect our financial results.

Our hedging transactions expose us to the risk that a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make such party unable to perform under the terms of the derivative contract, and we may not be able to realize the benefit of the derivative contract. Any default by a counterparty to these derivative contracts when they become due could have a material adverse effect on our financial condition and results of operations.

Our ability to collect payments from the sale of oil, natural gas and NGLs to our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fail to pay us for any reason, we could experience a material loss. We generally do not require our customers to post collateral, but we are managing our credit risk as a result of the current commodity price environment through the attainment of financial assurances from certain customers. In addition, if any of our significant customers cease to purchase our oil, natural gas and NGLs or reduce the volume of the oil, natural gas and NGLs that they purchase from us, the loss or reduction could have a detrimental effect on our revenues and may cause a temporary interruption in sales of, or a lower price for, our oil, natural gas and NGLs.

We also face credit risk through joint interest receivables. Joint interest receivables arise from billing entities who own partial working interests in the wells we operate. Though we often have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings, the inability or failure of working interest holders to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our ability to obtain financing on terms acceptable to us may be limited in the future by, among other things, increases in interest rates.

We require continued access to capital and our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. We may use our Credit Facility to finance a portion of our future growth, and these factors could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Volatility in the global financial markets, significant losses in financial institutions' U.S. energy loan portfolios, or environmental and social concerns may lead to a contraction in credit availability impacting our ability to finance our operations or our ability to refinance our Credit Facility or other outstanding indebtedness. An increase in interest rates could increase our interest expense and materially adversely affect our financial condition. A significant reduction in cash flow from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

The borrowing base under our Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs.

Our Credit Facility limits the amounts that we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually in the spring and fall. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments.

In the future, we may not be able to access adequate funding under our Credit Facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

The enactment of derivatives legislation 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.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has issued final regulations in certain areas, in other areas, final regulations and the scope of relevant definitions and/or exemptions still remain to be finalized. On January 24, 2020, U.S. banking regulators published a new approach for calculating the quantum of exposure of derivative contracts under their regulatory capital rules. This approach to measuring exposure is referred to as the standardized approach for counterparty credit risk or SA-CCR. It requires certain financial institutions to comply with significantly increased capital requirements for over-the-counter commodity derivatives beginning on January 1, 2022. In addition, on September 15, 2020, the CFTC issued a final rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, which has a compliance date of October 6, 2021. These two sets of regulations and the increased capital requirements they place on certain financial institutions may reduce the number of products and counterparties in the over-the-counter derivatives market available to us and could result in significant additional costs being passed through to end-users like us. The full impact of the Dodd-Frank Act's swap regulatory provisions and the related rules of the CFTC on our business will not be known until all of the rules to be adopted under the Dodd-Frank Act have been adopted and fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, 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. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

In addition, the European Union and other non-U.S. jurisdictions have implemented and continue to implement regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, which could have adverse effects on our operations similar to the possible effects on our operations of the Dodd-Frank Act's swap regulatory provisions and the rules of the CFTC.

Risks Related to our Class A Common Stock, Series A Preferred Stock and Capital Structure

We are a holding company. Our sole material asset is our equity interest in INR Holdings and we are accordingly dependent upon distributions from INR Holdings to pay taxes, make payments under the Tax Receivable Agreement and cover our corporate and other overhead expenses.

We are a holding company and have no material assets other than our equity interest in INR Holdings. For additional information, see "Item 1. Business—Corporate Reorganization." We have no independent means of generating revenue or cash flow, and our ability to pay our taxes and operating expenses (including payments due under the Tax Receivable Agreement, dated as of January 30, 2025, by and among the Company and the TRA Parties (as defined therein)(the "Tax Receivable Agreement")) or declare and pay dividends in the future, if any, is dependent upon the financial results and cash flows of INR Holdings and distributions we receive from INR Holdings. INR Holdings will continue to be treated as a partnership for U.S. federal income tax purposes and, as such, generally will not be subject to any entity-level U.S. federal income tax. Instead, any taxable income of INR Holdings will be allocated to holders of LLC Interests, including us. Accordingly, we will incur income taxes on our allocable share of any net taxable income of INR Holdings. Under the terms of the INR Holdings LLC Agreement, INR Holdings is obligated, subject to various limitations and restrictions, including with respect to our debt agreements, to make tax distributions to holders of LLC Interests, including us. To the extent INR Holdings has available cash, we intend to cause INR Holdings (a) to generally make pro rata distributions to its unitholders, including us, in an amount at least sufficient to allow us to pay our taxes and make payments under the Tax Receivable Agreement and (b) to reimburse us for our corporate and other overhead expenses through non-pro rata payments that are not treated as distributions under the INR Holdings LLC Agreement. To the extent that we are unable to make payments under the Tax Receivable Agreement for any reason, such payments will be deferred and will accrue interest until paid. We are limited, however, in our ability to cause INR Holdings and its subsidiaries to make these and other distributions to us due to the restrictions under our Credit Facility. To the extent that we need funds and INR Holdings or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Pearl, NGP, Quantum and Carnelian collectively hold a substantial majority of our capital stock and voting power.

As of March 5, 2026, Pearl owns INR Units and corresponding Class B common stock representing approximately 36.2% of our voting power, NGP owns INR Units and corresponding Class B common stock representing approximately 12.1% of our voting power, Quantum owns shares of Series A Preferred Stock representing approximately 16.1% of our voting power and Carnelian owns shares of Series A Preferred Stock representing approximately 4.4% of our voting power (together representing 68.8% of our combined voting power).

As set out in the amended and restated certificate of incorporation ("Charter"), based on their respective voting interest in us, NGP has the right to nominate one director and Pearl has the right to nominate a number of directors proportionate to their beneficial ownership of the combined voting power of our Class A common stock and Class B common stock. As of March 5, 2026, Pearl is entitled to nominate four members of our board of directors, and thereby is entitled to significant control of our management and affairs. As of March 5, 2026, while NGP maintains the right to nominate one member of the board of directors, NGP does not have a nominee on the board of directors. The Certificate of Designation also entitles

Carnelian to appoint one member of our board of directors. Further, although Pearl, NGP, Quantum and Carnelian are entitled to act separately and have no obligation to act together in their own respective interests with respect to their stock in us, they will together have an even greater voting interest in us and ability to control our management and affairs. In addition, they will be able to determine the outcome of all matters requiring stockholder approval, including mergers and other material transactions, and will be able to cause or prevent a change in the composition of our board of directors or a change of control of our company that could deprive our stockholders of an opportunity to receive a premium for their Class A common stock as part of a sale of our company. The existence of significant stockholders may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as Pearl, NGP, Quantum and Carnelian, or any of them individually, continue to control a significant amount of our voting power, they will be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of Pearl, NGP, Quantum and Carnelian may differ or conflict with the interests of our other stockholders. Moreover, this concentration of stock ownership may also adversely affect the trading price of our Class A common stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

Conflicts of interest could arise in the future between us and Pearl, NGP, Quantum, Carnelian and their respective affiliates, including their portfolio companies concerning conflicts over our operations or business opportunities.

Pearl, NGP, Quantum and Carnelian are investment firms and have investments in other companies in the energy industry. As a result, Pearl, NGP, Quantum and Carnelian may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are our customers or suppliers. As such, Pearl, NGP, Quantum or Carnelian or their respective portfolio companies may acquire or seek to acquire the same assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Any actual or perceived conflicts of interest with respect to the foregoing could have an adverse impact on the trading price of our Class A common stock.

An active, liquid trading market for our Class A common stock may not be maintained.

We can provide no assurance that we will be able to maintain an active trading market for our Class A common stock. The lack of an active market may impair your ability to sell your shares at the time you wish to sell them or at a price that you consider reasonable. An inactive market may also impair our ability to raise capital by selling our Class A common stock and our ability to acquire other companies, products or technologies by using our Class A common stock as consideration.

Certain of our directors have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Certain of our directors, who are responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including Pearl- or Carnelian-affiliated entities) that are in the business of identifying and acquiring oil and natural gas properties. The existing positions held by these directors may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor.

Our Series A Preferred Stock has rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our Class A common stock.

On February 23, 2026, Infinity issued and sold, pursuant to the Securities Purchase Agreement an aggregate 350,000 shares of Series A Preferred Stock to affiliates of Quantum and affiliates of Carnelian for consideration of $350 million. Quantum acquired 275,000 shares of Series A Preferred Stock and Carnelian acquired 75,000 shares of Series A Preferred Stock.

Our Series A Preferred Stock ranks senior to our Class A Common Stock with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our Class A common stock or could make it more difficult for us to sell our Class A common stock in the future. Holders of Series A Preferred Stock are entitled to dividends at a fixed rate that increases after the five year anniversary of the issuance of the Series A Preferred Stock. Dividends are payable quarterly in arrears, and dividends accrued through and including the second anniversary of the issuance of the Series A Preferred Stock may be paid, at the Company's option, in cash or in kind by increasing the initial liquidation preference of each share of Series A Preferred Stock by the amount of the applicable dividend, and thereafter must be paid in cash. Upon a change of control of the Company, any share of Series A Preferred Stock to be repurchased would be entitled to receive an amount in cash equal to the greater of (i) an internal rate of return of 13% per annum on the initial liquidation preference or (ii) a 1.3x return on the initial liquidation preference. Our obligation to pay dividends on our Series A Preferred Stock could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other Company purposes. Our obligations to the holders of the Series A Preferred Stock could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

The Certificate of Designation governing our Series A Preferred Stock contains covenants that may limit our business flexibility.

Subject to certain exceptions and ownership thresholds, the Certificate of Designation of Series A Convertible Preferred Stock of the Company (the "Certificate of Designation") requires the consent of the holders of Series A Preferred Stock holding a majority of the then-outstanding shares of Series A Preferred Stock is required for, among other things, certain amendments to the Company's organizational documents, issuances of senior or parity securities, payment of dividends, delisting from the NYSE or deregistration from Section 12 of the Exchange Act, formation of non-wholly owned subsidiaries, the incurrence of debt in excess of a certain threshold and any deviation from certain enumerated hedging requirements. The provisions may limit our business flexibility, limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

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

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

Our Charter and amended and restated bylaws ("Bylaws"), as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our Class A common stock.

Our Charter authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our Charter 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:

- authorizing "blank check" preferred stock that our board of directors could issue to increase the number of outstanding shares to discourage a takeover attempt;
- prohibiting stockholders from acting by written consent at any time when Pearl beneficially owns, in the aggregate, less than 35% in voting power of our common stock;
- limitations on the ability of our stockholders to call special meetings;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock (or a majority of the voting power of all outstanding shares of capital stock if Pearl beneficially owns at least 35% of the voting power of all such outstanding shares) be obtained to amend our Bylaws, to remove directors or to amend our certificate of incorporation;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal, our Bylaws; and

- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

In addition, certain change of control events have the effect of accelerating the payment due under our Tax Receivable Agreement, which could be substantial and accordingly serve as a disincentive to a potential acquirer of our company. For additional information, see "—In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits we realize, if any, in respect of the tax attributes subject to the Tax Receivable Agreement."

Moreover, the rights of the holders of Series A Preferred Stock under the Certificate of Designation may delay or prevent a change of control of the Company. The holders of Series A Preferred Stock are entitled to redeem their shares upon a change of control in an amount in cash equal to the greater of (i) an internal rate of return of 13% per annum on their initial liquidation preference or (ii) a 1.3x return on their initial liquidation preference.

Any provision of our Charter, Bylaws or Delaware law that has the effect of delaying, preventing or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their shares of our Class A common stock and could also affect the price that some investors are willing to pay for our Class A common stock.

We cannot assure you that we will be able to pay dividends on our Class A common stock.

Our board of directors may elect to declare cash dividends on our Class A common stock, subject to our compliance with applicable law, and depending on, among other things, economic conditions, our financial condition, results of operations, projections, liquidity, earnings, legal requirements, and restrictions in the agreements governing our indebtedness (as further discussed below). The payment of any future dividends will be at the discretion of our board of directors. The declaration and amount of any future dividends is subject to the discretion of our board of directors, and we have no obligation to pay any dividends at any time. We have not adopted, and do not currently expect to adopt, a written dividend policy. Our ability to pay dividends depends on our receipt of cash dividends from our operating subsidiaries, which may further restrict our ability to pay dividends as a result of the laws of their jurisdiction of organization, agreements of our subsidiaries or covenants under any existing and future outstanding indebtedness we or our subsidiaries incur.

Our Credit Facility contains restrictions on the payment of dividends. Such restrictions allow us to pay dividends only when certain conditions are met, including certain required leverage ratio and financial metrics. For additional information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Financing Agreements—Credit Facility." Our Certificate of Designation also contains restrictions on our ability to pay dividends. Due to the foregoing, we cannot assure you that we will be able to pay a dividend in the future or continue to pay a dividend after we commence paying dividends.

Future sales of our Class A common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute ownership in us.

We may issue additional shares of Class A common stock or convertible securities in future public offerings.

Certain of the Legacy Owners are party to a registration rights agreement with us that requires us to effect the registration of their shares in certain circumstances. Quantum and Carnelian are party to a separate registration rights agreement that also requires us to effect the registration of their shares. The registration rights agreements provide for demand and "piggyback" rights that would facilitate future sales of our Class A common stock in the public market. Any sales of such securities may depress the price of our shares. Furthermore, we filed a registration statement with the SEC on Form S-8 providing for the registration of 6,477,778 shares of our Class A common stock issued or reserved for issuance under the Infinity Natural Resources, Inc. Omnibus Incentive Plan. Subject to the satisfaction of vesting conditions, the expiration of lock-up agreements and the requirements of Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"), shares registered under the registration statement on Form S-8 have been made available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our Class A common stock or securities convertible into Class A common stock or the effect, if any, that future issuances and sales of shares of our Class A common stock will have on the market price of our Class A common stock. Sales of substantial amounts of our Class A common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A common stock. This impact could be increased to the extent there is a less active trading market for our shares.

We cannot guarantee that our Share Repurchase Program will be fully consummated or that it will enhance long-term stockholder value. Share repurchases could also increase the volatility of the trading price of our Class A common stock and could diminish our cash reserves.

Although our board of directors has authorized the Share Repurchase Program (as defined below), the program does not obligate us to repurchase any specific dollar amount or to acquire any specific number of shares of Class A common stock. The actual timing and amount of any share repurchases remains subject to a variety of factors, including stock price, trading volume, market conditions, compliance with applicable legal requirements, restrictions in our debt agreements, and other general business considerations. The Share Repurchase Program has no expiration date, but it may be modified, suspended or terminated at any time, and we cannot guarantee that the Share Repurchase Program will be fully consummated or that it will enhance long-term stockholder value. Furthermore, our execution of the Share Repurchase Program could affect the trading price of our Class A common stock and increase volatility, and any announcement of a termination of, or downward revision in, the Share Repurchase Program may result in a decrease in the trading price of our Class A common stock. In addition, the Share Repurchase Program could diminish our cash reserves.

We limit the liability of, and indemnify, our directors and officers.

Although our directors and officers are accountable to us and must exercise good faith, good business judgement and integrity in handling our affairs, our Charter and the indemnification agreements that we entered into with all of our non-employee directors and officers provide that our non-employee directors and officers will be indemnified to the fullest extent permitted under Delaware law. As a result, our stockholders may have fewer rights against our non-employee directors and officers than they would have absent such provisions in our Charter and indemnification agreements, and a stockholder's ability to seek and recover damages for a breach of fiduciary duties may be reduced or restricted.

Pursuant to our Charter and indemnification agreements, each non-employee director and officer who is made a party to a legal proceeding because he or she is or was a non-employee director or officer, is indemnified by us from and against any and all liability, except that we may not indemnify a non-employee director or officer: (i) for breach of the director's or officer's duty of loyalty to us or our stockholders, (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (iii) with respect to any director, pursuant to Section 174 of the Delaware General Corporation Law (the "DGCL"), (iv) for any transaction from which the director or officer derived an improper personal benefit or (v) with respect to any officer, in any action by or in the right of us. We are required to pay or reimburse attorney's fees and expenses of a non-employee director or officer seeking indemnification as they are incurred, provided the non-employee director or officer executes an agreement to repay the amount to be paid or reimbursed if there is a final determination by a court of competent jurisdiction that such person is not entitled to indemnification.

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a result of the IPO, we became a public company, and, as such, we need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements may occupy a significant amount of time of our board of directors and management and significantly increase our costs and expenses. We need to continue our efforts to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act for our fiscal year ending December 31, 2025, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until as late as our annual report for the fiscal year ending December 31, 2030. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed. Compliance with these requirements may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain directors' and officers' liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including disclosure about our executive compensation, that apply to other public companies.

We are classified as an "emerging growth company" under the JOBS Act. In addition, we have reduced SOX compliance requirements, as discussed elsewhere. For as long as we are an emerging growth company we will not be required to, among other things, (a) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (b) provide certain disclosure regarding executive compensation required of larger public companies or (c) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company up until the last day of the fiscal year following the fifth anniversary of the IPO, or such earlier time that we have more than $1.235 billion of revenues in a fiscal year, have more than $700.0 million in market value of our Class A common stock held by non-affiliates (and have been a public company for at least 12 months), or issue more than $1.0 billion of non-convertible debt over a three-year period.

Because we have elected to take advantage of the extended transition period pursuant to Section 107 of the JOBS Act, our financial statements may not be comparable to those of other public companies.

Section 107 of the JOBS Act provides that an emerging growth company can use the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. This permits an emerging growth company to delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We are choosing to take advantage of this extended transition period and, as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for private companies. Accordingly, our financial statements may not be comparable to companies that comply with public company effective dates, and our stockholders and potential investors may have difficulty in analyzing our operating results by comparing us to such companies.

Terms of subsequent financings may adversely impact stockholder equity.

If we raise more equity capital from the sale of Class A common stock, institutional or other investors may negotiate terms more favorable than the current prices of our Class A common stock. If we issue debt securities, the holders of the debt would have a claim to our assets that would be prior to the rights of stockholders until the debt is paid. Interest on these debt securities would increase costs and could negatively impact our operating results.

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

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

Our Charter designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to bring a claim in a different judicial forum for disputes with us or our directors, officers, employees or agents.

Our Charter provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (a) any derivative action or proceeding brought on our behalf, (b) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (c) any action asserting a claim arising pursuant to any provision of the DGCL, our Charter or Bylaws, or (d) any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Notwithstanding the foregoing sentence, the federal district courts of the United States of America shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under U.S. federal securities laws, including the Securities Act and the Exchange Act. This choice of forum may limit a stockholder's ability to bring a claim in a different judicial forum for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our Charter inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our financial condition or results of operations.

We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may claim, and the amounts of such payments could be significant.

In connection with the consummation of the IPO, we entered into a Tax Receivable Agreement with the Legacy Owners. This agreement generally provides for the payment by us to the Legacy Owners of 85% of the net cash savings, if any, in U.S. federal, state and local income tax that we (a) actually realize with respect to taxable periods ending after the IPO or (b) are deemed to realize in the event of a change of control (as defined under the Tax Receivable Agreement, which includes certain mergers, asset sales and other forms of business combinations and certain changes to the composition of our board of directors) or if the Tax Receivable Agreement terminates early (at our election or as a result of our breach) with respect to any taxable periods ending on or after such change of control or early termination event, in each case, as a result of (i) the tax basis increases resulting from the exchange of INR Units and the corresponding surrender of an equivalent number of shares of Class B common stock by the Legacy Owners for a number of shares of Class A common stock on a one-for-one basis or, at our option, the receipt of an equivalent amount of cash (the "Exchange Right") pursuant to the INR Holdings LLC Agreement and (ii) deductions arising from imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. We will retain the benefit of the remaining 15% of these cash savings, if any. If we experience a change of control or the Tax Receivable Agreement terminates early, we could be required to make a substantial, immediate lump-sum payment. For additional information, see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Tax Receivable Agreement."

The payment obligations under the Tax Receivable Agreement are our obligations and not obligations of INR Holdings. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the Tax Receivable Agreement. The amounts payable, as well as the timing of any payments, under the Tax Receivable Agreement are dependent upon future events and assumptions, including the timing of the exchanges of INR Units along with surrendering a corresponding number of our Class B common stock, the price of our Class A common stock at the time of each exchange, the extent to which such exchanges are taxable transactions, the amount of the exchanging INR Unit Holder's tax basis in its INR Units at the time of the relevant exchange, the depreciation, depletion and amortization periods that apply to the increase in tax basis, the amount and timing of taxable income we generate in the future, the U.S. federal, state and local income tax rates then applicable, and the portion of our payments under the Tax Receivable Agreement that constitute imputed interest or give rise to depreciable, depletable or amortizable tax basis. We expect that the payments that we will be required to make under the Tax Receivable Agreement could be substantial. Any payments made by us to the Legacy Owners under the Tax Receivable Agreement will not be available for reinvestment in INR Holdings (or indirectly, its business) and generally will reduce the amount of overall cash flow that might have otherwise been available to us. The term of the Tax Receivable Agreement commenced on January 30, 2025 and will continue until all such tax benefits have been utilized or expired and all required payments are made, unless we exercise our right to terminate the Tax Receivable Agreement (or the Tax Receivable Agreement is terminated due to other circumstances, including our breach of a material obligation thereunder or certain mergers or other changes of control) by making the termination payment specified in the agreement. In the event that the Tax Receivable Agreement is not terminated, the payments under the Tax Receivable Agreement are not anticipated to commence until 2030 at the earliest (with respect to the tax year 2025).

The payments under the Tax Receivable Agreement will not be conditioned upon a holder of rights under the Tax Receivable Agreement having a continued ownership interest in us or INR Holdings. In addition, certain rights under the Tax Receivable Agreement (including the right to receive payments) will be transferable in connection with transfers permitted thereunder. For additional information, see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Tax Receivable Agreement."

In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits we realize, if any, in respect of the tax attributes subject to the Tax Receivable Agreement.

If we experience a change of control (as defined under the Tax Receivable Agreement, which includes certain mergers, asset sales and other forms of business combinations and certain changes to the composition of our board of directors) or the Tax Receivable Agreement terminates early (at our election or as a result of our breach), we could be required to make a substantial, immediate lump-sum payment. This payment would equal the present value of hypothetical future payments that could be required under the Tax Receivable Agreement. The calculation of the hypothetical future payments will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including (a) the sufficiency of taxable income to fully utilize the tax benefits, (b) any INR Units (other than those held by us) outstanding on the termination date are exchanged on the termination date and (c) the utilization of certain loss carryovers. Our ability to generate net taxable income is subject to substantial uncertainty. Accordingly, as a result of the assumptions, the required lump-sum payment may be significantly in advance of, and could materially exceed, the realized future tax benefits to which the payment relates. This payment obligation could (i) make us a less attractive target for an acquisition, particularly in the case of an acquirer that cannot use some or all of the tax benefits that are the subject of the Tax Receivable Agreement and (ii) result in holders of our Class A common stock receiving substantially less consideration in connection with a change of control transaction than they would receive in the absence of such obligation. Accordingly, the Legacy Owners' interests may conflict with those of the holders of our Class A common stock.

As a result of either an early termination or a change of control, we could be required to make payments under the Tax Receivable Agreement that exceed our actual cash tax savings under the Tax Receivable Agreement. Consequently, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

In the event that our payment obligations under the Tax Receivable Agreement are accelerated upon certain mergers, other forms of business combinations or other changes of control, the consideration payable to holders of our Class A common stock could be substantially reduced.

If we experience a change of control (as defined under the Tax Receivable Agreement), our obligation to make a substantial, immediate lump-sum payment could result in holders of our Class A common stock receiving substantially less consideration in connection with a change of control transaction than they would receive in the absence of such obligation. The amount due will be equal to the present value of the anticipated future tax benefits that are the subject of the Tax Receivable Agreement, based on certain assumptions outlined in the Tax Receivable Agreement (including the discount rate to be used and that we will have sufficient taxable income to realize all potential tax benefits that are subject to the Tax Receivable Agreement), which payment may be made significantly in advance of the actual realization, if any, of such future tax benefits. Such cash payment to the Legacy Owners could be greater than the specified percentage of any actual benefits we ultimately realize in respect of the tax benefits that are subject to the Tax Receivable Agreement. In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control. Further, holders of rights under the Tax Receivable Agreement may not have an equity interest in us or INR Holdings. Accordingly, the interests of holders of rights under the Tax Receivable Agreement may conflict with those of the holders of our Class A common stock. For additional information, see "—In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits we realize, if any, in respect of the tax attributes subject to the Tax Receivable Agreement" and "Item 13. Certain Relationships and Related Transactions, and Director Independence—Tax Receivable Agreement." There can be no assurance that we will be able to fund or finance our obligations under the Tax Receivable Agreement. We may need to cause INR Holdings to incur debt and make distributions to the holders of LLC Interests, including us, to finance payments under the Tax Receivable Agreement to the extent our cash resources are insufficient to meet our obligations under the Tax Receivable Agreement as a result of timing discrepancies or otherwise.

We will not be reimbursed for any payments made under the Tax Receivable Agreement in the event that any tax benefits are subsequently disallowed.

Payments under the Tax Receivable Agreement will be based on the tax reporting positions that we will determine, which are complex and factual in nature, and the IRS or another tax authority may challenge all or part of the tax basis increases upon which payments under the Tax Receivable Agreement are based, as well as other related tax positions that we take, and a court could sustain such challenge. The holders of rights under the Tax Receivable Agreement will not reimburse us for any payments previously made under the Tax Receivable Agreement if such basis increases or other benefits are subsequently disallowed, except that excess payments made to any such holder will be netted against payments otherwise to be made, if any, to such holder after our determination of such excess. However, we might not determine that we have effectively made an excess cash payment to a Legacy Owner for a number of years following the initial time of such payment and, if any of our tax reporting positions are challenged by a taxing authority, we will not be permitted to reduce any future cash payments under the Tax Receivable Agreement until any such challenge is finally settled or determined. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any, and may not be able to recoup those payments, which could adversely affect our liquidity. The applicable U.S. federal income tax rules for determining applicable tax benefits we may claim are complex and factual in nature, and there can be no assurance that the IRS or a court will not disagree with our tax reporting positions. As a result, payments could be made under the Tax Receivable Agreement significantly in excess of any actual cash tax savings that we realize in respect of the tax attributes with respect to a Legacy Owner that are the subject of the Tax Receivable Agreement.

If INR Holdings were to become a publicly traded partnership taxable as a corporation for U.S. federal income tax purposes, we and INR Holdings might be subject to potentially significant tax inefficiencies, and we would not be able to recover payments previously made by us under the Tax Receivable Agreement even if the corresponding tax benefits were subsequently determined to have been unavailable due to such status.

We intend to operate such that INR Holdings does not become a publicly traded partnership taxable as a corporation for U.S. federal income tax purposes. A "publicly traded partnership" is a partnership the interests of which are traded on an established securities market or are readily tradable on a secondary market or the substantial equivalent thereof. Under certain circumstances, exchanges of INR Units pursuant to the Exchange Right or other transfers of INR Units could cause INR Holdings to be treated as a publicly traded partnership. Applicable U.S. Treasury regulations provide for certain safe harbors from treatment as a publicly traded partnership, and we intend to operate such that exchanges or other transfers of INR Units qualify for one or more such safe harbors.

If INR Holdings were to become a publicly traded partnership, significant tax inefficiencies might result for us and for INR Holdings, including as a result of our inability to file a consolidated U.S. federal income tax return with INR Holdings. In addition, we would no longer have the benefit of certain increases in tax basis covered under the Tax Receivable Agreement, and we would not be able to recover any payments previously made by us under the Tax Receivable Agreement, even if the corresponding tax benefits (including any claimed increase in the tax basis of INR Holdings' assets) were subsequently determined to have been unavailable.

In certain circumstances, INR Holdings will be required to make tax distributions to us and the INR Unit Holders, and the tax distributions that INR Holdings will be required to make may be substantial.

INR Holdings will be treated as a partnership for U.S. federal income tax purposes and, as such, is not subject to U.S. federal income tax. Instead, taxable income will be allocated to the INR Unit Holders and us. Pursuant to the INR Holdings LLC Agreement, INR Holdings will generally make pro rata cash distributions, or tax distributions, to the INR Unit Holders and us. However, as the managing member of INR Holdings, we may determine to increase the tax rate applicable to tax distributions by INR Holdings.

Funds used by INR Holdings to satisfy its tax distribution obligations will not be available for reinvestment in our business. Moreover, the tax distributions that INR Holdings will be required to make may be substantial.

The Legacy Owners' interests may not be fully aligned with the interests of the holders of our Class A common stock.

The Legacy Owners' interests may not be fully aligned with yours, which, due to the concentrated ownership of our common stock by the Legacy Owners, could lead to actions that are not in your best interests. Because the Legacy Owners hold their economic interest in our business primarily through INR Holdings, the Legacy Owners may have conflicting interests with holders of shares of our Class A common stock. For example, the Legacy Owners may have different tax positions from us, which could influence their decisions regarding whether and when we should dispose of assets or incur new or refinance existing indebtedness, especially in light of the existence of the Tax Receivable Agreement, and whether and when we should respond to a breach of any of our material obligations under the Tax Receivable Agreement, undergo certain changes of control for purposes of the Tax Receivable Agreement or terminate the Tax Receivable Agreement. In addition, the structuring of future transactions may take into consideration these tax or other considerations even where no similar benefit would accrue to us. For additional information, see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Tax Receivable Agreement."

Further, if the IRS makes audit adjustments to INR Holdings' U.S. federal income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from INR Holdings rather than from the Legacy Owners directly, in which case we may economically bear a portion of such taxes (including any applicable penalties and interest) even though we did not economically benefit from the income giving rise to such taxes. INR Holdings may be permitted to make an election which would have the effect of requiring the IRS to collect any such taxes (including penalties and interest) from the members of INR Holdings (including the Legacy Owners), rather than from INR Holdings, but there can be no assurance that INR Holdings will be permitted to or will make this election. If, as a result of any such audit adjustment, INR Holdings is required to make payments of taxes, penalties and interest, INR Holdings' cash available for distributions to us may be substantially reduced.

Further, the Legacy Owners, who are the only holders of INR Units other than us, have the right to consent to certain amendments to the INR Holdings LLC Agreement, as well as to certain other matters. The Legacy Owners may exercise these voting rights in a manner that conflicts with the interests of the holders of our Class A common stock. Pearl, one of the Legacy Owners, holds a number of shares of our non-economic Class B common stock that will permit it to have significant influence over our overall management and direction. Circumstances may arise in the future when the interests of the Legacy Owners conflict with the interests of our stockholders.

Risks Related to Environmental and Regulatory Matters

Our operations are subject to stringent environmental, health and safety laws and regulations that may expose us to significant costs and liabilities that could exceed current expectations.

We are subject to stringent and complex federal, state and local environmental, health and safety ("EHS") laws and regulations, including laws and regulations governing the discharge of materials into the environment, emissions controls and other environmental protection and occupational health and safety concerns. Any discharge by us of natural gas, NGLs, oil and other pollutants into the air, soil or water may give rise to liabilities on our part to the government and third parties. Certain environmental laws and regulations, such as CERCLA and comparable state laws, may impose strict, retroactive and joint and several, liability for environmental contamination, including the release of hazardous substances, which could render us potentially liable for remediation costs, damage to natural resources or other damages, without regard to fault or the legality of the conduct at the time of the release or if contamination was caused by prior owners, operators or other third parties. Governmental agencies, citizen organizations, neighboring landowners and other third parties could file claims for personal injury, property damage and recovery of response costs. Remediation costs and other damages arising as a result of environmental laws and regulations, and costs associated with changes to existing EHS laws and regulations or the interpretation thereof, or the adoption of new EHS laws and regulations over time could adversely impact our financial condition or results of operations. Moreover, any failure by us to comply with applicable EHS laws and regulations could result in the imposition of administrative, civil or criminal penalties or the issuance of injunctions that could delay or prohibit operations, which could in turn have a material adverse effect on our business.

We are required to hold certain U.S. federal, state and local EHS permits and may require new or amended EHS permits from time to time, including with respect to stormwater discharges, waste handling and disposal, or air emissions, which may subject us to new or revised permitting conditions that may be onerous or with which it may be costly to comply. These permits and authorizations often contain numerous compliance requirements, including monitoring and reporting obligations and operational restrictions, such as emissions limits. Noncompliance with necessary permits or the failure to obtain additional permits could subject us to future penalties, operating restrictions, or delays in obtaining new or amended permits or permit renewals that could have a material adverse effect on our business, financial condition or results of operations.

EHS laws and regulations are constantly evolving and may become increasingly complicated and more stringent in the future. In addition, new or additional laws and regulations, new interpretations of existing requirements or changes in enforcement policies could impose unforeseen liabilities, significantly increase compliance costs, or result in delays of, or denial of rights to conduct, our development programs. For example, in June 2015, the EPA and the Corps issued a rule under the CWA defining the scope of the EPA's and the Corps' jurisdiction over WOTUS, which was repealed in December 2019 and replaced in June 2020 by the Navigable Waters Protection Rule (the "NWPR") before ever taking effect. A coalition of states and cities, environmental groups and agricultural groups challenged the NWPR, which was vacated by a federal district court in August 2021. In January 2023, the EPA and the Corps issued a final rule to revise the definition of WOTUS to put back into place the pre-2015 definition; however, this definition of WOTUS was impacted by the U.S. Supreme Court's May 2023 decision in Sackett v. EPA, wherein the Court held that the jurisdiction of the CWA extends only to those adjacent wetlands that are indistinguishable from traditional navigable bodies of water due to a continuous surface connection. In September 2023, the EPA and the Corps published a direct-to-final rule redefining WOTUS to amend the January 2023 rule and align with the decision in Sackett. Subsequent litigation from approximately half of the states and other plaintiffs challenging the September 2023 rule is ongoing, and the pre-2015 definition of WOTUS is in effect in these states while litigation continues. Further, in November 2025, the EPA and the Corps issued a proposed rule revising the definition of WOTUS with the stated aim of conforming to the U.S. Supreme Court's decision in Sackett and revising certain regulatory terms, such as "relatively permanent", "tributary" and "continuous surface connection"; a final rule is expected in early 2026, and litigation is highly likely following issuance of the final rule. Accordingly, future implementation and enforcement of these rules and policies is uncertain at this time. To the extent a new rule or further litigation expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Such potential regulations or litigation could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which in turn could materially adversely affect our results of operations and financial position.

Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. In 2021, the U.S. 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 13, 2026, EPA announced 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. Future implementation and enforcement of these rules and policies is uncertain at this time.

Future EHS laws and regulations (or changes to existing laws and regulations or their interpretation) may also negatively impact natural gas and oil exploration, production, gathering and transportation companies, which in turn could have a material adverse effect on our business, financial conditions and results of our operations.

We may be involved in legal and regulatory proceedings that could result in substantial liabilities.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury, environmental damage or property damage matters, in the ordinary course of our business. Such legal and regulatory proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management or other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in civil or criminal liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results or financial condition. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material. As of December 31, 2025, we are not aware of any potentially material legal proceeding that has been brought against us.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and adversely affect our business.

More stringent laws and regulations relating to climate change and GHG emissions may arise from a variety of sources, including international, national, regional and state levels of government and associated administrative bodies and could cause us to incur material expenses to comply with such laws and regulations. In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and in the absence of comprehensive federal legislation on GHG emission control, the EPA has adopted regulations pursuant to the CAA to reduce GHG emissions from various sources, but the future of these regulations is not clear. For example, in June 2016, the EPA published New Source Performance Standards 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 March 2024, the EPA adopted more stringent rules requiring the monitoring and reporting of GHG emissions from specified new, modified and reconstructed onshore and offshore oil, natural gas and NGL production sources in the U.S. on an annual basis, known as Subpart OOOOb, as well as standards for existing sources, known as OOOOc, which include certain segments of our operations. OOOOb and OOOOc, which went into effect in May 2024 and require, among other things, the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions), standardization of installation and maintenance of emission control devices, 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, two years until March 2026 to develop and submit their plans for reducing methane emissions from existing sources. The final emissions guidelines under Subpart OOOOc provide three years until 2029 from the plan submission deadline for existing sources to comply. The final rule is subject to ongoing litigation but remains in effect. 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, also 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. Consequently, future implementation and enforcement of GHG emissions regulations under the CAA remain uncertain at this time. Compliance with these and other air pollution control monitoring and permitting requirements, along with the required associated technical investments, has the potential to delay the development of natural gas projects and increase our costs of development, which costs could be significant.

Additionally, in 2022, the IRA was signed into law, which could accelerate the transition to a lower carbon economy. The IRA provides incentives for the development of renewable energy, clean hydrogen, clean fuels and supporting infrastructure and carbon capture and sequestration. In addition, the IRA includes a methane emissions reduction program that amends the Clean Air Act to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a “Waste Emissions Charge” on certain natural gas and oil sources that are already required to report under the EPA’s Greenhouse Gas Reporting Program. To implement the program, in May 2024, EPA finalized revisions to the Greenhouse Gas Reporting Program for the oil and natural gas sector. The emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the Methane Emissions Reduction Program. However, in March 2025, President Trump signed Congress’ Joint Resolution of Disapproval of the Waste Emissions Charge, and in May 2025 the EPA issued a final rule to remove the WEC regulations from the Code of Federal Regulations. In addition, 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 oil and natural gas industry) until 2034. Consequently, future implementation and enforcement of these rules remains uncertain at this time.

Additionally, some states have issued mandates to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and potential cap-and-trade programs. For example, Pennsylvania has taken steps to bring the state into a consortium of Northeastern and Mid-Atlantic States, the Regional Greenhouse Gas Initiative (“RGGI”), that sets price and declining limits on CO2 emissions from power plants. In December 2021, the Pennsylvania Attorney General approved a proposed regulation which would allow Pennsylvania to join RGGI, although implementation of the regulation was delayed by litigation. In November 2025, Pennsylvania’s governor signed legislation that withdrew the state’s participation in RGGI. However, in May 2024, the Pennsylvania Climate Emissions Reduction Initiative was introduced in the Pennsylvania General Assembly, which, if enacted, would adopt a RGGI-like carbon-pricing program for the state. At this time, it is unclear to what extent, if any, Pennsylvania will adopt an emissions cap-and-trade program for the state. Most of these types of programs require major sources of emissions or major producers of fuels to acquire and subsequently surrender emission allowances, with the number of allowances available being reduced each year until a target goal is achieved. The cost of these allowances could increase over time. While new laws and regulations that are aimed at reducing GHG emissions could increase demand for natural gas, they may also result in increased costs for permitting, equipping, monitoring and reporting GHGs associated with natural gas production and use.

Internationally, the United States joined the international community and the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change in Paris, France in 2015, which resulted in the Paris Agreement, requiring member states to individually determine and submit non-binding emissions reduction targets. However, in January 2025, the Trump Administration issued executive orders 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. The withdrawal became effective in January 2026. On January 7, 2026, President Trump 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 uncertain at this time. At the same time, various state and local governments have committed to continue furthering the goals of the Paris Agreement and many of these initiatives are expected to continue. We may also be subject to risks related to more restrictive requirements for the development of pipeline infrastructure or LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. For example, in January 2024, the Biden Administration announced a temporary pause on pending decisions on new exports of LNG to countries that the U.S. does not have free trade agreements with, pending Department of Energy review of the underlying analyses for authorization, including an assessment of the impact of GHG emissions. However, in January 2025, the Trump Administration issued an executive order directing the Department of Energy to restart reviews of applications for approvals of LNG export projects as expeditiously as possible, and in April 2025 the Department of Energy rescinded its Policy Statement on Export Commencement Deadlines in Authorizations to Export Natural Gas to Non-Free Trade Agreement Countries, effectively ending the temporary pause on new exports of LNG. Separately, in April 2024, the European Union adopted a regulation to track and reduce methane emissions in the energy sector, including requiring new monitoring, reporting and verification measures to be applied by importers of oil, natural gas and coal into the European Union by January 1, 2027, and "maximum methane intensity values" must be met by 2030 and every year thereafter. Each member state will have the power to impose administrative penalties for failure to comply and the standard will be mandatory for supply contracts signed after the law takes effect. This and other changes in law and governmental policy may have impacts on our business that are difficult to anticipate.

More broadly, the adoption and implementation of new or more stringent international, federal, state, or local legislation, regulations or other regulatory initiatives related to climate change or GHG emissions from oil and natural gas facilities could result in increased costs of compliance or costs of consumption, thereby reducing demand for our products, and 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, and to monitor and report on GHG emissions, including establishing internal controls for collecting, measuring and analyzing information related to such matters. Additionally, political, litigation, and financial risks may result in (a) restriction or cancellation of certain oil and natural gas production activities, (b) incurrence of obligations for alleged damages resulting from climate change or (c) impairment of our ability to continue operating in an economic manner. To the extent that governmental entities in the U.S. or other countries implement or impose climate change regulations on the oil and gas industry, it could have a material adverse effect on our business, including by restricting our ability to execute on our business strategy; requiring additional capital, compliance, operating and maintenance costs; increasing the cost of our products and services; reducing demand for our products and services; reducing our access to financial markets or creating greater potential for governmental investigations or litigation.

In addition, the U.S. Supreme Court's decision in Loper Bright Enterprises v. Raimondo to overrule Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc. ended the concept of general deference to regulatory agency interpretations of laws and introduced new complexity for federal agencies and administration of climate change policy and regulatory programs. However, many of these initiatives at the international and state levels are expected to continue. Consequently, legislation and regulatory programs to address climate change or reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. In addition, any 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.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, limits to the areas in

which we can operate and reductions in our oil, natural gas and NGL production, which could adversely affect our production and business.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations, as does much of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding such activities. In addition, the EPA finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that certain activities associated with hydraulic fracturing may impact drinking water resources under some circumstances. To date, the EPA has taken no further action in response to the 2016 report.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. New federal legislation regulating hydraulic fracturing may be considered again in the future. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, Ohio, Pennsylvania and West Virginia have each adopted a law requiring oil and natural gas operators to disclose chemical ingredients used to hydraulically fracture wells, and Ohio requires oil and natural gas operators to conduct pre-drill baseline water quality sampling of certain water wells near a proposed horizontal well. Unlike Ohio, Pennsylvania does not require oil and natural gas operators to conduct pre-drilling water supply sampling, but Pennsylvania law incentivizes testing as such sampling can preserve a legal defense regarding pollution of water supply. Additional states could also decide to place prohibitions on hydraulic fracturing. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have banned and others seek to ban hydraulic fracturing altogether. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays, curtailment in or exclusion from the pursuit of exploration, development or production activities.

Changes to trade regulation, quotas, duties or tariffs, caused by the changing U.S. and geopolitical environments or otherwise, may increase our costs, result in fewer growth capital opportunities or projects, limit the amount of raw materials and products that we can import, decrease demand for certain of our services or otherwise adversely impact our business.

International trade disputes, geopolitical tensions and military conflicts have led, and continue to lead, to new and increasing export restrictions, trade barriers, tariffs and other trade measures that can increase our manufacturing and transportation costs, limit our ability to sell to certain customers or markets, limit our ability to procure, or increase our costs for, components or raw materials, impede or slow the movement of our goods across borders, or otherwise restrict our ability to conduct operations. The U.S. has recently instituted or proposed changes in trade policies that include the negotiation or termination of trade agreements, the imposition of higher tariffs on imports into the U.S., economic sanctions on individuals, corporations or countries and other government regulations affecting trade between the U.S. and other countries. Such imposition of tariffs on certain goods imported into the U.S. has triggered retaliatory actions from certain foreign governments potentially resulting in a “trade war.” A “trade war” or other governmental action related to tariffs or international trade agreements or policies could increase our costs, reduce the demand or opportunity to deploy growth capital in our businesses at attractive rates of return, limit the amount of raw materials, components and other products that we can import, restrict our customers’ ability to deploy growth capital or transport products and therefore decrease demand for certain of our services and/or adversely affect the U.S. economy or certain sectors thereof and, thus, adversely impact our businesses.

Prolonged negative investor sentiment toward upstream oil and natural gas focused companies could limit our access to capital funding, damage our reputation and adversely impact our business, financial condition and results of operations.

Certain segments of the investor community have developed negative sentiment toward investing in our industry. 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. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the natural gas and oil sector based on social and environmental considerations. 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. Certain commercial and investment banks based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Institutional lenders who provide financing to energy companies may be more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Ultimately, these developments could reduce the availability of capital funding to us for potential development projects or to refinance our existing indebtedness, each of which could have a material adverse effect on our business, prospects, financial condition, results of operations and cash flows.

Legislation or regulatory initiatives intended to address seismic activity, as well as government reviews of such activities, could restrict our drilling and production activities, as well as our ability to dispose of saltwater produced from such activities, which could limit our ability to produce oil, natural gas and NGLs economically and have a material adverse effect on our business.

Local, state and federal regulatory agencies, including in Pennsylvania and Ohio, have in the past focused on a possible connection between hydraulic fracturing-related activities, particularly the underground injection of wastewater into disposal wells and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, several lawsuits have been filed in some states, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states and local municipalities, including in Pennsylvania, are seeking to impose or have imposed additional requirements, including obligations regarding the permitting of produced water disposal wells or otherwise assessing the relationship between seismicity and the use of such wells. To the extent any new regulations are adopted to restrict hydraulic fracturing activities or the disposal of fluids associated with such activities, it may adversely affect our business, financial condition and results of operations.

We dispose of some of the saltwater produced from our drilling and production operations by injecting it into wells pursuant to permits issued to us and third parties by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of saltwater produced from our drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

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

Our operations may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife species and/or habitats. The ESA and (in some cases) comparable state laws were established to protect endangered and threatened species and similar protections are offered to migratory birds under the MBTA and other federal and state statutes. The FWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in material restrictions to land use and may materially delay or prohibit land access for drilling activities. In April 2024, the U.S. Fish and Wildlife Service finalized three rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. Among other changes to the rules, a determination of whether a species is threatened or endangered will be made “without reference to possible economic or other impacts of such determination,” and protections that are granted to species found to be endangered will be automatically extended to species found to be threatened. The revised rules also make it easier to designate areas as critical for a species’ survival, even if the species is no longer found in those areas. However, in January 2025, President Trump issued an executive order directing agencies to use, to the maximum extent permissible, the ESA regulation on consultations in emergencies to facilitate the domestic energy supply. The executive order also requires the quarterly convening of the Endangered Species Act Committee to ensure prompt and efficient review of all submissions for potential actions that could facilitate energy development.

Further, in April 2024, the FWS and National Marine Fisheries Service proposed to redefine “harm” under the ESA to mean affirmative acts that are directed immediately and intentionally against a particular animal, excluding acts or omissions that indirectly cause injury. In addition, in November 2025, the Trump Administration proposed several rules that would significantly alter protections for plants and animals. One such proposed rule would rescind a rule that automatically extends protections for endangered species to threatened species. Another such proposed rule would change regulations for listing species as endangered or threatened as well as for designating critical habitats. A third such proposed rule would reinstate the framework for evaluating the benefits and costs of designating a critical habitat by considering factors such as economic impact, impact on national security, and other relevant impacts. The FWS is expected to issue final rules in 2026. Like the ESA, similar protections are offered to migratory birds under MBTA, which makes it illegal to, among other things, hunt, capture, kill, possess, sell or purchase migratory birds, nests or eggs without a permit. This prohibition covers most bird species in the U.S. The Department of the Interior issued a legal opinion in December 2017, followed by a final rule in January 2021, that narrowed certain protections afforded to migratory birds pursuant to the MBTA. The Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment to the Department of the Interior’s plan to develop regulations that authorize incidental take under certain prescribed conditions. However, in April 2024, the U.S. Department of Interior issued a memo, M-37085, which clarified that the MBTA only prohibits the intentional “take” of migratory birds. As a result, future implementation and enforcement of these rules under the ESA and MBTA remains uncertain at this time.

These rules, and any future rules, could materially affect our operations and development. For instance, permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. A critical habitat or suitable habitat designation in areas where we conduct our business could result in material restrictions to land use and may materially delay, or prohibit land access for, oil, natural gas and NGL development. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves. 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.

We are subject to risks related to climate change, which could have a material adverse effect on our business, financial condition and results of operations.

Increased attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on combating climate change, together with technological advances in fuel economy and energy generation devices as well as climate change activism, governmental requirements and societal expectations on companies to address climate change, may create competitive conditions that result in reduced demand for the oil, natural gas or NGLs we produce for our customers’ products. Such requirements, advancements and expectations may include, for instance, requirements to implement fuel conservation measures, regulations favoring renewable energy resources, increasing consumer demand for alternative forms of energy and lower emission products or services and other changes in consumer behavior. The potential impact of changing demand for oil, natural gas or NGLs services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows or those of the customers we serve, which could, in turn, affect demand for our products. Such developments may also adversely impact, among other things, the availability of necessary third-party services and facilities as well as market prices of, or our access to, raw materials such as energy and water, which may increase our operational costs and adversely affect our ability to successfully carry out our business strategy. Further, the enactment of climate change-related policies and initiatives across the market at the corporate level and/or investor community level may in the future result in increases in our compliance costs and other operating costs and have other adverse effects (e.g., greater potential for governmental investigations or litigation, reductions in demand for our products or stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels).

Furthermore, negative public perception regarding the oil and gas industry resulting from, among other things, concerns raised by advocacy groups about climate change, emissions, hydraulic fracturing, seismicity or oil spills may lead to increased litigation risk and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation for us or our customers, thereby reducing demand for our products.

Finally, many scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere produce climate changes that may have significant physical effects, such as increased frequency and severity of storms, droughts, floods or other climatic events. Such effects could adversely affect or delay demand for our products, or our customers' products, or cause us to incur significant costs in preparing for, or responding to, the effects thereof. Energy needs could increase or decrease as a result of weather conditions, depending on the duration and magnitude of any such weather events, and adversely impact our operating costs or revenues. To the extent the frequency of extreme weather events increases, due to climate change or otherwise, this could impact operations in various ways, including damage to or disruption of operations at our facilities, increased insurance premiums or increases to the cost of providing service or changes to the availability of insurance coverage, reduced availability of electrical power, road accessibility and transportation facilities, as well as impacts on personnel, supply chain, distribution chain or customers, as well as potentially increased costs for, or difficulty procuring, consistent levels of insurance coverages in the aftermath of such effects. Such physical risks may also impact the infrastructure on which we rely to produce or transport our products. In addition, while our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or been prepared for every eventuality. Further, demand for our products, or our customers' products, may increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate changes, such as to the extent warmer weathers reduce the demand for energy for heating purposes. The effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. If any such effects were to occur as a result of climate change or otherwise, they could have a material adverse effect on our assets, our financial condition and our results of operations. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a diversified portfolio of properties.

Attention to Environmental, Social and Governance ("ESG") and sustainability matters may expose us to additional risk, which could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

Companies across all industries are facing scrutiny from a variety of stakeholders related to their ESG and sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on ESG matters (including with respect to climate change) as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to concern for ESG and sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition and/or stock price could be materially and adversely affected.

Moreover, while we may 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. ESG-related disclosure continue to be an area where we may be, or may become, subject to required disclosures in certain jurisdictions, depending on our purported nexus to such jurisdictions and any such mandatory disclosures may similarly necessitate the use of hypothetical, projected or estimated data, some of which is not controlled by us and is inherently subject to imprecision. Disclosures reliant upon 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. Failure or a perception of failure to implement our ESG strategy could damage our reputation, causing our investors or consumers to lose confidence in us and negatively impacting our operations. 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.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

While our pipeline systems have not been regulated by FERC under the NGA or the NGPA, FERC has adopted certain regulations and policies that may subject certain of our otherwise non-FERC jurisdictional facilities to market transparency, anti-market-manipulation, and oversight requirements, including annual reporting requirements. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Under the EPAct of 2005, as of 2025 FERC has civil penalty authority under the NGA and the NGPA to impose penalties for violations of up to $1,584,648 per day for each violation, subject to further adjustment for inflation in 2026, in addition to disgorgement of profits associated with any violation. Failure to comply with FERC rules and regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Risk Management and Strategy

We rely on information technology and data to operate our business effectively and recognize the importance of implementing and maintaining cybersecurity systems and processes that allow us to protect the confidentiality, integrity and availability of our information systems and the data residing within them.

We maintain a comprehensive cybersecurity risk program to effectively identify, assess, manage, and respond to cybersecurity risks and incidents. Our program is implemented by in-house personnel with experience in cybersecurity fields and is further enhanced by external partners that specialize in cybersecurity services. Our program is built on recognized industry standards and frameworks that are regularly evaluated and updated to address emerging threats.

Key elements of our cybersecurity risk management program include regular and thorough risk assessments to identify potential cybersecurity threats across our operations, the implementation of appropriate multi-layered security controls and advanced monitoring systems, comprehensive employee cybersecurity awareness training and education programs delivered throughout the year. A key element of our cybersecurity response program is the regular and redundant point-in-time backup of critical configurations and files.

Governance

Our board of directors oversees our cybersecurity risk management program through the Audit Committee. Our management team, including our Vice President of Technology, provides periodic updates on cybersecurity matters to the Audit Committee, which relays them to the board of directors as needed. Our Vice President of Technology has primary responsibility for assessing and managing cybersecurity risks and leading our overall cybersecurity posture, including the engagement of external third parties to assist us. Our Vice President of Technology has 30 years of experience in the field of information systems and cybersecurity.

Impact of Risks from Cybersecurity Threats

As of the date of this Annual Report, we are not aware of any previous cybersecurity incidents that have materially affected or are reasonably likely to materially affect the Company, including our business strategy, results of operations and financial condition. We acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents, material or otherwise, remains. Despite the implementation of our cybersecurity processes, our security measures cannot guarantee that a significant cybersecurity incident will not occur. While we devote resources to our security measures designed to protect our systems and information, no security measure is infallible. For more information about the cybersecurity risks we face, refer to “Item 1A. Risk Factors” in this Annual Report.

ITEM 2. PROPERTIES

Information about our properties is incorporated herein by reference to “Item 1. Business” of Part I of this Annual Report. Our corporate headquarters is located in leased office space in Morgantown, West Virginia. We also lease office space in Stamford, Connecticut, Houston, Texas and Marietta, Ohio.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are subject to mediation, arbitration, litigation, or claims arising in the ordinary course of business. The results of any current or future claims or proceedings cannot be predicted with certainty, and regardless of the outcome, litigation can have an adverse impact on us because of defense and litigation costs, diversion of management resources, reputational harm, and other factors. We do not believe that any existing claims or proceedings will have a material effect on our business, consolidated financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

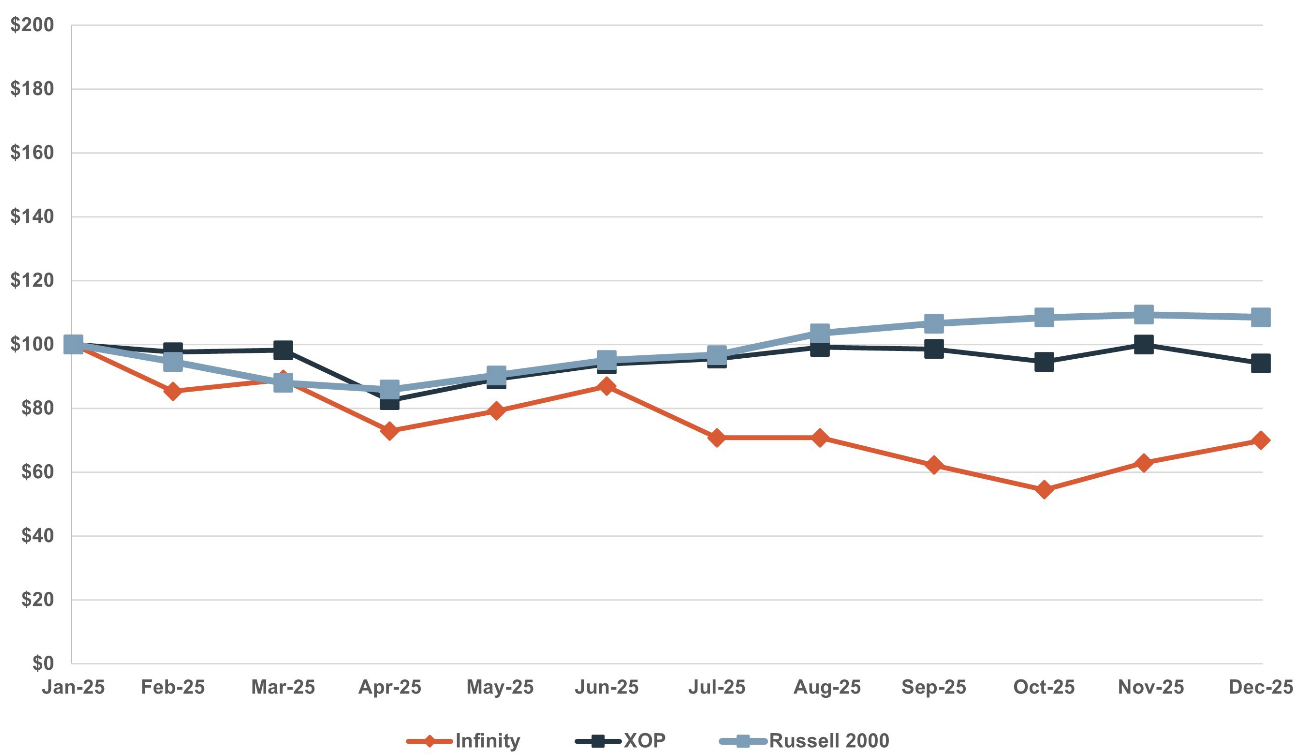
On January 31, 2025, our Class A common stock began trading on the NYSE under the symbol "INR." Prior to that time, there was no public market for our Class A common stock. There is no public trading market for our Class B common stock.

Holders of Common Stock

As of March 5, 2026, there were six stockholders of record of our Class A common stock and 14 holders of record of our Class B common stock. The number of holders does not include the stockholders for whom shares of our Class A common stock are held in a "nominee" or "street" name.

Stock Performance Graph

The performance graph below compares the cumulative total stockholder return on our Class A common stock (under the ticker symbol "INR") to that of the Russell 2000 Index ("Russell 2000") and the Standard & Poor's 500 Oil and Gas Exploration & Production ETF ("XOP"). The "cumulative total return" assumes that $100 was invested, including reinvestment of dividends, if any, in our Class A common stock, the Russell 2000, and XOP on January 31, 2025 (the date our Class A common stock began trading on the NYSE) and tracks it through December 31, 2025. The results shown in the graph below are not necessarily indicative of future stock price performance.



The information in this Annual Report appearing under the heading "Stock Performance Graph" is being "furnished" pursuant to Item 2.01(e) of Regulation S-K under the Securities Act and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act and shall not be deemed incorporated by reference into any filing under the Securities Act of the Exchange Act except to the extent that we specifically request that it be treated as such.

Dividend Policy

We currently intend to retain all available funds and any future earnings to fund the development and growth of our business, and therefore we do not anticipate declaring or paying any cash dividends on our Class A common stock in the foreseeable future. Except in certain limited circumstances, holders of our Class B common stock are not entitled to participate in any dividends declared by our board of directors. Furthermore, because we are a holding company, our ability to pay cash dividends on our Class A common stock depends on our receipt of cash distributions from INR Holdings. Any distributions by INR Holdings will be made to the INR Unit Holders and us on a pro rata basis in accordance with our respective percentage ownership of INR Units. Our Credit Facility and Certificate of Designation contain certain covenants that restrict, subject to certain exceptions, our ability to pay dividends. Holders of Series A Preferred Stock are entitled to dividends (i) at the rate of 8% per annum until the five year anniversary of the issuance of the Series A Preferred Stock, and (ii) at the rate of 12% per annum after the five year anniversary of the issuance of the Series A Preferred Stock. Holders of Series A Preferred Stock will also be entitled to participate in any dividends or other distributions declared or paid in cash on the shares of Class A common stock, on an as-converted basis. Any future determination as to the declaration and payment of dividends, if any, will be at the discretion of our board of directors and subject to the requirements of applicable law, compliance with contractual restrictions and covenants in the agreements governing our future indebtedness. Any such determination will also depend upon our business prospects, results of operations, financial condition, cash requirements and availability and other factors that our board of directors may deem relevant.

Securities Authorized for Issuance Under Equity Compensation Plans

Information about securities authorized for issuance under our equity compensation plans is incorporated herein by reference to “Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” of Part III of this Annual Report.

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

On November 10, 2025, our board of directors authorized a common share repurchase program (the “Share Repurchase Program”), whereby we may purchase up to an aggregate of $75 million of our Class A common stock. Repurchases under the Share Repurchase Program may be made from time to time in the open market, in privately negotiated transactions, through purchases made in accordance with Rule 10b5-1 of the Exchange Act, or by such other means as will comply with applicable state and federal securities laws. The timing of any such repurchases will depend on market conditions, contractual limitations and other considerations. The Share Repurchase Program may be extended, modified, suspended or discontinued at any time, and does not obligate the Company to repurchase any dollar amount or number of shares.

The Inflation Reduction Act of 2022 (the "IRA 2022") provides for, among other things, the imposition of a 1% non-deductible U.S. federal excise tax on the fair market value of any stock repurchased by a publicly traded domestic corporation during any taxable year, with the fair market value of such repurchased stock reduced by the fair market value of certain stock issued by such corporation during such taxable year (such exercise tax, the "Stock Buyback Tax"). In the past, there have been proposals to increase the amount of the Stock Buyback Tax from 1% to 4%; however, it is unclear whether such a change in the amount of the excise tax will be enacted and, if enacted, how soon any such change could take effect. The Stock Buyback Tax first applied to our stock repurchase program in the year ended December 31, 2025, and will continue to apply in subsequent taxable years.

The following table sets forth our share purchase activity for each period presented:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased Under Plans or Programs
October 1, 2025 – October 31, 2025	—	$ —	—	$ —
November 1, 2025 – November 30, 2025	—	—	—	—
December 1, 2025 – December 31, 2025	87,132	$ 13.60	87,132	$ 73,814,971
Total	87,132	$ 13.60	87,132	

ITEM 6. [RESERVED]

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

The following should be read in conjunction with our financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks, and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, future market prices for oil, natural gas and NGLs, future production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, inflation, regulatory changes, and other uncertainties, as well as those factors discussed in "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors" in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

We are a growth oriented independent energy company focused on the acquisition, development, and production of hydrocarbons in the Appalachian Basin. We are focused on creating shareholder value through the identification and disciplined development of low-risk, highly economic oil and natural gas assets while maintaining a strong and flexible balance sheet. Our operations are focused on the Utica Shale in eastern Ohio as well as our dry gas assets in both the Marcellus and Utica Shales in southwestern Pennsylvania, providing highly economic stacked development inventory that leverages shared infrastructure and operational efficiencies. Our portfolio is balanced across oil and natural gas assets, allowing us to optimize our development plan to respond to changes in commodity prices over time. Unless expressly stated otherwise, the operating and financial information presented in this Annual Report does not give effect to the completion of the Antero Acquisition or the Preferred Investment (each as defined herein).

Market Conditions and Operational Trends

Our revenue, profitability, and ability to return cash to our equity holders can depend on factors beyond our control, such as economic, political, and regulatory developments that impact market supply and demand. Prices for crude oil, natural gas and NGLs have experienced significant fluctuations in recent years and may continue to fluctuate widely in the future.

The oil and gas industry is cyclical and commodity prices are highly volatile. During the period from January 1, 2024 through December 31, 2025, spot prices for NYMEX WTI crude oil ranged from $68.24 per Bbl to $85.35 per Bbl, while the range for NYMEX Henry Hub natural gas spot prices was between $1.57 per MMBtu and $3.91 per MMBtu. We expect that the commodity market will continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. We use a derivative portfolio and firm sales contracts to mitigate the risks of price volatility.

The following table highlights the quarterly average price trends for NYMEX WTI spot prices for crude oil and NYMEX Henry Hub index price for natural gas since the first quarter of 2024:

	2024					2025				
	Q1	Q2	Q3	Q4	YE	Q1	Q2	Q3	Q4	YE
Oil (per Bbl)	$77.56	$81.72	$76.24	$70.73	$76.56	$71.84	$64.63	$65.74	$59.64	$65.46
Gas (per MMBtu)	$ 2.25	$ 1.89	$ 2.15	$ 2.79	$ 2.77	$ 3.65	$ 3.44	$ 3.07	$ 3.55	$ 3.43

Lower commodity prices and lower futures curves for oil and natural gas prices may result in impairments of our proved oil and natural gas properties or undeveloped acreage and may materially and adversely affect our operating cash flows, liquidity, financial condition, results of operations, future business and operations, and/or our ability to finance planned capital expenditures, which could in turn impact our ability to comply with covenants under our Credit Agreement. Lower realized prices may also reduce the borrowing base under our Credit Agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that has been mortgaged to the lenders. Upon a redetermination, if any borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under the Credit Agreement.

Recent Developments

Antero Acquisition

On February 23, 2026, we and Northern completed the Antero Acquisition of the Upstream Assets from the Upstream Sellers and the Midstream Assets from the Midstream Sellers. The Upstream Assets include approximately 42,500 net surface acres in the Ohio Utica Shale across Guernsey, Noble, Belmont, and Monroe Counties, which are highly contiguous with and complementary to our existing Ohio operations. The assets include an estimated 370.1 Bcfe of proved reserves and approximately 110 identified undeveloped drilling locations across multiple phase windows. The Midstream Assets include approximately 141 miles of natural gas gathering pipelines, with capacity to support up to 600 MMcf/d, and approximately 90 miles of freshwater and produced-water infrastructure. These assets enhance our vertical integration and are expected to reduce operating costs, improve margins, and enable efficient full-field development.

Infinity will operate substantially all of the Antero Ohio Assets pursuant to joint development and cooperation agreements entered into with Northern at closing. We funded the transaction with cash on hand, the proceeds of the Preferred Investment and borrowings under our Credit Facility, which was amended and expanded in connection with closing.

Chase Acquisition

On January 20, 2026, the Company and INR Holdings entered into a purchase and sale agreement (the “Chase Purchase Agreement”) with Chase Oil Corporation, a New Mexico corporation, and certain other sellers (each a “Chase Seller” and, collectively, “Chase Sellers”) for the acquisition of certain non-operated rights, title and interests in oil and gas properties, rights and related assets located in the State of Pennsylvania from the Chase Sellers (the “Chase Acquisition”), for consideration of 2,517,194 shares of the Company’s Class A common stock. The Chase Acquisition closed on January 20, 2026, simultaneously with the execution of the Chase Purchase Agreement.

Share Repurchase Program

On November 10, 2025, our board of directors authorized the Share Repurchase Program, whereby we may purchase up to an aggregate of $75 million of our Class A common stock. The Company repurchased 87,132 shares for a total of $1.2 million during the quarter ended December 31, 2025. As of December 31, 2025, we had $73.8 million remaining under the Share Repurchase Program. Repurchases under the Share Repurchase Program may be made from time to time in the open market, in privately negotiated transactions, through purchases made in accordance with Rule 10b5-1 of the Exchange Act, or by such other means as will comply with applicable state and federal securities laws.The timing of any such repurchases will depend on market conditions, contractual limitations and other considerations. The Share Repurchase Program may be extended, modified, suspended or discontinued at any time, and does not obligate the Company to repurchase any dollar amount or number of shares.

Amendments to Credit Agreement

On December 5, 2025, INR Holdings entered into that certain Third Amendment to Credit Agreement (the “Third Credit Agreement Amendment”). The Third Credit Agreement Amendment, among other things, amended certain provisions relating to hedging requirements and restrictions, debt incurrences and permitted acquisitions in the Credit Agreement.

On February 23, 2026, INR Holdings entered into that certain Fourth Amendment to Credit Agreement (the “Fourth Credit Agreement Amendment”). The Fourth Credit Agreement Amendment, among other things, amends certain provisions to (i) increase the aggregate elected commitment amount from $375.0 million to $875.0 million, (ii) increase the borrowing base from $375.0 million to $875.0 million and (iii) remove the credit spread adjustment that was previously applicable to all Secured Overnight Financing Rate (“SOFR”) borrowings under the Credit Agreement.

Preferred Investment

On February 23, 2026, we issued and sold, pursuant to the Securities Purchase Agreement an aggregate 350,000 shares of Series A Preferred Stock to affiliates of Quantum and affiliates of Carnelian for consideration of $350 million. After deducting placement agent fees, Infinity received net proceeds of approximately $337.1 million. Quantum acquired 275,000 shares of Series A Preferred Stock and Carnelian acquired 75,000 shares of Series A Preferred Stock. The Company used the proceeds of the Preferred Investment to fund a portion of the Antero Acquisitions and will use any remaining proceeds for general corporate purposes.

Sources of Revenues

We derive our revenues predominantly from the sale of our oil and natural gas production and the sale of NGLs that are extracted from our natural gas during processing. Our production is entirely from within the continental United States and is similarly sold to purchasers within the United States; however, some of our production revenues are attributable to customers who may export our products.

Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Oil, natural gas, and NGL prices are market driven and have been historically volatile, and we expect that future prices will continue to fluctuate. During 2025 and 2024, our oil, natural gas, and NGL revenues were comprised of 50% and 63%, respectively, from the sale of oil, 36% and 20%, respectively, from the sale of natural gas, and 14% and 17%, respectively, from the sale of NGLs.

Midstream activities revenues, which consist of gathering, compression, and water handling, are derived from our ownership of INR Midstream. Our gathering and compression revenues relate to activities located within the dry gas areas of southwestern Pennsylvania. Our water handling revenues relate to activities associated with delivering water for stimulation activities in both eastern Ohio and southwestern Pennsylvania.

Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Corporate Reorganization. The 2023 and 2024 consolidated financial statements included in this Annual Report are based on the financial statements of our predecessor, INR Holdings, prior to our Corporate Reorganization in connection with the IPO as described in “Item 1. Business—Corporate Reorganization.” Our historical financial data may not yield an accurate indication of what our actual results would have been if those transactions had been completed at the beginning of the periods presented or of what our future results of operations are likely to be. In connection with the closing of the IPO, all outstanding performance-based incentive units of INR Holdings vested.

Interest Expense. In connection with the IPO, we materially reduced our indebtedness through the repayment of substantially all of our outstanding borrowings under the Credit Facility with net proceeds of the IPO. As a result, our cash interest expense was lower in 2025 than 2024.

Income Taxes. Our predecessor, INR Holdings, was organized as a limited liability company not subject to federal income taxes. Accordingly, no provision for federal income taxes was provided for in our historical results of operations for 2024 because taxable income was passed through to our members. Following the Corporate Reorganization, we are a corporation under the Internal Revenue Code of 1986, as amended (the “Code”), and we will report income tax benefit or expense for 2025 and going forward.

Non-Cash Compensation Expense. In connection with the closing of the IPO, all outstanding incentive units of INR Holdings vested. Consequently, the Company recognized $126.1 million of non-recurring, non-cash stock compensation expense related to these awards, in accordance with the guidance provided by ASC 710.

Results of Operations

For the Year Ended December 31, 2025, Compared to the Year Ended December 31, 2024

The following table provides the components of our net revenues and net production for the periods indicated, as well as each period's average prices (before and after the effects of derivatives) and average daily production volumes:

	For the Year Ended December 31,		Increase / (Decrease)	
	2025	2024	$	%
Net revenues (in thousands):				
Oil sales	$173,612	$161,514	$12,098	7%
Natural gas sales	127,448	51,157	76,291	149%
Natural gas liquids sales	49,315	45,035	4,280	10%
Oil, natural gas, and natural gas liquids sales	$350,375	$257,706	$92,669	36%
Average sales prices:				
Oil price (per Bbl)	$56.48	$67.86	($11.38)	(17%)
Effects of derivative settlements on average price (per Bbl)	$4.50	($0.93)	$5.43	584 %
Oil price including the effects of derivatives (per Bbl)	$60.98	$66.93	($5.95)	(9%)
Wtd. Average NYMEX WTI price for oil (per Bbl)[(2)(3)]	$64.81	$76.42	($11.61)	(15%)
Oil differential to NYMEX	($8.33)	($8.56)	$0.23	3%
Natural gas price (per Mcf)	$2.80	$1.81	$0.99	54 %
Effects of derivative settlements on average price (per Mcf)	$0.01	$0.66	($0.65)	(98%)
Natural gas price including the effects of derivatives (per Mcf)	$2.81	$2.47	$0.34	14%
Wtd. Average NYMEX Henry Hub price for natural gas (per MMBtu)[(2)(3)]	$3.41	2.27	$1.14	50%
Natural gas differential to NYMEX	($0.62)	($0.46)	($0.16)	(35)%
NGL price excluding GP&T (per Bbl)	$22.32	$26.14	($3.82)	(15%)
Effects of derivative settlements on average price (per Bbl)	($0.10)	$2.52	($2.62)	(104%)
NGL price including the effects of derivatives (per Bbl)	$22.22	$28.66	($6.44)	(22%)
Net production				
Oil (MBbls)	3,074	2,380	694	29%
Natural gas (MMcf)	45,596	28,291	17,305	61%
NGL (Bbls)	2,209	1,723	486	28%
Net production (MBoe)[(1)]	12,882	8,818	4,064	46%
Average daily net production				
Oil (Bbls/d)	8,422	6,502	1,920	30%
Natural gas (Mcf/d)	124,920	77,297	47,623	62%
NGLs (Bbls/d)	6,052	4,708	1,344	29%
Average daily net production (Boe/d)[(1)]	35,293	24,093	11,200	46%

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(2) Based on Netherland, Sewell and Associates Inc. ("NSAI") found at https://netherlandsewell.com/resources/pricing-data/ and U.S. Energy Information Administration commodity pricing.

(3) Weighted average is based on INR's production in a given month during the course of the calendar year.

Revenues

Oil, natural gas, and NGL sales. During 2025 and 2024, our oil, natural gas, and NGL revenues were comprised of 50% and 63%, respectively, from the sale of oil, 36% and 20%, respectively, from the sale of natural gas, and 14% and 17%, respectively, from the sale of NGLs. Net revenues for the year ended December 31, 2025 increased by $92.7 million, or 36%, compared to the year ended December 31, 2024. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Net production volumes for oil increased 29%, natural gas increased 61% and NGLs increased 28%, respectively, between periods. The oil, natural gas and NGL production volume increase resulted from placing 23 wells on production across our oil weighted assets in the Ohio Utica's volatile oil window and our natural gas weighted assets in the Marcellus Shale in Pennsylvania during the fourth quarter of 2024 and 2025. The addition of these wells contributed to the overall increase of 11.2 MBoe/d, or 46%, in production relative to the prior period.

Average realized natural gas prices rose 54% during the period driven by higher NYMEX prices and improved differentials. Oil prices fell 17%, reflecting lower NYMEX WTI prices. NGL prices decreased 15% due to lower Mont Belvieu spot prices and changes in product mix.

Operating Expenses

	For the Year Ended December 31,		Change	
	2025	2024	Amount	Percent
(in thousands)				
Gathering, processing, and transportation	$ 54,779	$ 49,290	$ 5,489	11%
Lease operating	26,675	28,154	(1,479)	(5%)
Production and ad valorem taxes	5,918	1,071	4,847	453%
Depreciation, depletion and amortization	103,751	73,726	30,025	41%
General and administrative	153,413	13,045	140,368	1076%
Total operating expenses	$ 344,536	$ 165,286	$ 179,250	108%
($ per Boe)				
Gathering, processing, and transportation	$ 4.25	$ 5.59	$ (1.34)	(24%)
Lease operating	2.07	3.19	(1.12)	(35%)
Production and ad valorem taxes	0.46	0.12	0.34	283 %
Depreciation, depletion and amortization	8.05	8.36	(0.31)	(4%)
General and administrative	11.91	1.48	10.43	705%
Total operating expenses	$ 26.74	$ 18.74	$ 8.00	43%

Gathering, processing, and transportation. Gathering, processing, and transportation ("GP&T") for the year ended December 31, 2025, increased $5.5 million compared to the year ended December 31, 2024. This increase was attributed to additional wells brought online in Ohio between periods. GP&T per Boe was $4.25 for the year ended December 31, 2025, which represents a decrease of $1.34 per Boe, or 24%, from the prior period. The decrease in per-unit GP&T rate was primarily attributable to increased production volumes in our natural gas-weighted areas of Pennsylvania, which are subject to lower GP&T rates on our internal gathering systems. This shift in volume mix reduced our overall average GP&T rate, as these areas incur fewer processing charges compared to our wet gas-weighted areas in Ohio, where the NGLs require additional processing.

Lease operating. Lease operating expense ("LOE") for the year ended December 31, 2025, decreased $1.5 million compared to the prior period. LOE per Boe was $2.07 for the year ended December 31, 2025, which represents a decrease of $1.12 per Boe, or 35%, from the prior period. This decrease in LOE was primarily related to a combination of (a) lower fixed and semi-variable well costs, such as water disposal, equipment rentals, repair work, wellhead chemicals, labor and electricity, associated with a higher well count from new producing wells drilled or acquired and (b) higher volumes from our Pennsylvania Marcellus development.

Production and ad valorem taxes. Production and ad valorem taxes for the year ended December 31, 2025, increased $4.8 million compared to the prior year. Production taxes in Ohio are based on our production at the wellhead, while ad valorem taxes are generally based on the assessed taxable value of our proved developed oil and gas properties and vary across the different counties in which we operate. Production taxes in Pennsylvania are assessed on producing wells by imposing an impact fee determined based on the market price for natural gas, which commences on the date the well is initially spud and continues for a period of 15 years.

Depreciation, Depletion and Amortization. For the year ended December 31, 2025, depreciation, depletion and amortization ("DD&A") expense was $103.8 million, an increase of $30.0 million over the prior period. The primary factor contributing to higher DD&A expense in 2025 was the increase in our overall production volumes between periods, which resulted in an average DD&A rate of $7.81 per Boe.

General and Administrative Expenses. General and administrative ("G&A") expenses for the year ended December 31, 2025 were $153.4 million compared to $13.0 million for the prior year. This increase was primarily due to higher payroll and employee costs, including a one-time non-cash stock compensation expense of $126.1 million expense recognized at IPO.

Net Gain (Loss) on Derivative Instruments. Net gains and losses are a function of (i) changes in derivative fair values associated with fluctuations in the forward price curves for the commodities underlying each of our hedge contracts outstanding; and (ii) monthly cash settlements on any closed out hedge positions during the period.

The following table presents gains and losses on our derivative instruments for the periods indicated:

	Year Ended December 31,	
(in thousands)	2025	2024
Realized cash settlement gains (losses)	$ 12,213	$ 28,360
Non-cash mark-to-market derivative gain (losses)	46,194	(50,407)
Total	$ 58,407	$ (22,047)

For the Year Ended December 31, 2024, Compared to the Year Ended December 31, 2023

Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2024 Annual Report on Form 10-K filed with the SEC for a discussion of the results of operations for the year ended December 31, 2024 compared to the year ended December 31, 2023.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operations, borrowings incurred under our Credit Facility and proceeds from sales of equity securities. Going forward, we expect our primary sources of liquidity to be cash flows from operations, borrowings incurred under our Credit Facility, proceeds from offerings of debt or equity securities, such as the Preferred Investment, or proceeds from the sale of oil and gas properties. Our future cash flows are subject to a number of variables, including oil and natural gas prices, which have been and will likely continue to be volatile. Lower commodity prices can negatively impact our cash flows and our ability to access debt or equity markets, and sustained low oil and natural gas prices could have a material and adverse effect on our liquidity position. To date, our primary uses of capital have been for drilling and development capital expenditures and the acquisition of oil and natural gas properties.

We continually evaluate our capital needs and compare them to our capital resources. Our total capital expenditures incurred for development during the year ended December 31, 2025 were $326.2 million, which includes $274.7 million on drilling and completion activities, $16.1 million on midstream and $35.5 million on land activities. We funded our capital expenditures for the year ended December 31, 2025 from cash flows from operations and borrowings incurred under our Credit Facility. Our development capital budget for 2026 is $450 million to $500 million, which includes drilling and completions and midstream capital expenditures. We expect to fund our 2026 capital expenditures budget through a combination of cash flows from operations and additional borrowings under our Credit Facility, as well as the proceeds of the Preferred Investment. Our ability to utilize cash flows from operations to fund our development program is driven by our oil and gas production, current commodity prices and our commodity hedge positions in place.

We operate the vast majority of our acreage and therefore can largely control the amount and timing of our capital expenditures. Accordingly, we can choose to defer or accelerate a portion of our planned capital expenditures depending on a variety of factors, including but not limited to: (i) prevailing and anticipated prices for oil and natural gas; (ii) the success of our drilling activities; (iii) the availability of necessary equipment, infrastructure and capital; (iv) the receipt and timing of required regulatory permits and approvals; (v) seasonal conditions; (vi) property or land acquisition costs; and (vii) the level of participation by other working interest owners.

In February 2025, we completed our IPO of 15.2 million shares of our Class A common stock at a price to the public of $20.00 per share, resulting in net cash proceeds of $286.5 million after deducting underwriting discounts and commissions. We used all of the net proceeds after paying certain offering expenses to repay borrowings outstanding under our Credit Facility.

On February 23, 2026, we closed the Antero Acquisition for consideration of approximately $720 million net to Infinity. See "Item 1. Business—Recent Acquisition—Antero Acquisition." We funded the transaction with cash on hand, the proceeds of the Preferred Investment and borrowings under our Credit Facility, the borrowing base and aggregate elected commitment amount of which increased from $375.0 million to $875.0 million in connection with closing.

In connection with the closing of the Antero Acquisition, we also completed a private placement of Series A Convertible Preferred Stock, which generated gross proceeds of $350 million and net proceeds of $337.1 million after deducting placement agent fees. The proceeds from the Preferred Investment were used to fund a portion of the acquisition. The Series A Preferred Stock provides long-term capital with no stated maturity; however, it accrues cumulative dividends that may be paid in kind for a limited period, after which dividends must be paid in cash, subject to restrictions under our Credit Facility. Any dividends paid in kind increase the liquidation preference of the Series A Preferred Stock and may increase future cash requirements. We believe the Preferred Investment enhances our overall liquidity and financial flexibility while supporting the execution of our development and acquisition strategy.

Our liquidity requirements also include operating expenses, which have been impacted by elevated levels of inflation. High oil prices have historically led to more development activity in oil-focused shale basins and resulted in service cost inflation across all U.S. shale basins, including our areas of operation. Ongoing inflationary pressures may result in increases to the costs of our oilfield goods, services and personnel, which would, in turn, cause our capital expenditures and operating costs to rise. We closely monitor costs and are cost conscious in managing our operations. We may solicit bids from multiple vendors or contractors or source materials from multiple suppliers to take advantage of cost competition, and we may buy surplus materials if we can acquire them on attractive terms. Where we anticipate elevated costs may be more sustained, such as in the cost of services, we may enter into contracts with certain service providers to lock in rates. We are also strategic in the duration of our contracts to provide flexibility to take advantage of cost declines when they occur. Sustained levels of high inflation have also caused the U.S. Federal Reserve and other central banks to increase interest rates, which has raised the cost of capital and increased our interest expense.

Although we cannot provide any assurance that cash flows from operations or other sources of needed capital will be available to us at acceptable terms, or at all, and noting that our ability to access the public or private debt or equity capital markets at economic terms in the future will be affected by general economic conditions, the domestic and global oil and financial markets, our operational and financial performance, the value and performance of our debt or equity securities, prevailing commodity prices and other macroeconomic factors outside of our control, we believe that based on our current expectations and projections, we have sufficient liquidity to fund future operations and to meet obligations as they become due for at least one year following the date that our consolidated financial statements are issued.

Cash Flow Activity

Our financial condition and results of operations, including our liquidity and profitability, are significantly affected by the prices that we realize for our oil, natural gas and NGLs and the volumes of oil and natural gas that we produce. Oil, natural gas and NGLs are commodities for which established trading markets exist.

Accordingly, our operating cash flow is sensitive to a number of variables, the most significant of which are the volatility of oil, natural gas and NGL prices and production levels both regionally and across the United States, the availability and price of alternative fuels, infrastructure capacity to reach markets, costs of operations, and other variable factors. We monitor factors that we believe could be likely to influence price movements including new or expanded oil and natural gas markets, gas imports, LNG and other exports, and regional and industry-wide capital intensity levels.

Our produced volumes have a high correlation to our level of capital expenditures such that our ability to fund it through operating and financing cash flows may be affected by multiple factors discussed further herein.

The following summarizes our cash flow activity for the periods indicated:

(in thousands)	Year Ended December 31, 2025	Year Ended December 31, 2024
Net cash provided by operating activities	$ 261,787	$ 177,666
Net cash used in investing activities	(430,167)	(256,118)
Net cash provided by financing activities	169,026	79,151
Net increase in cash and cash equivalents	$ 646	$ 699

Analysis of Cash Flow Changes Between the Years Ended December 31, 2025 and 2024

Operating activities

For the year ended December 31, 2025, we generated $261.8 million of cash from operating activities, an increase of $84.1 million from the prior year. Cash provided by operating activities increased primarily due to higher production volumes and associated revenues as compared to the prior year. These factors were partially offset by higher severance and ad valorem taxes, GP&T, G&A, and lower realized prices for oil and natural gas liquids during the year ended December 31, 2025 as compared to the prior year. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and on fluctuations in our operating costs between periods.

For the year ended December 31, 2024, we generated $177.7 million of cash from operating activities, an increase of $71.2 million from the prior year. Cash provided by operating activities increased primarily due to higher production volumes and associated revenues as compared to the prior year. These factors were partially offset by higher LOE, severance and ad valorem taxes, GP&T, G&A, interest expense and lower realized prices for oil and natural gas during the year ended December 31, 2024 as compared to the prior year. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and on fluctuations in our operating costs between periods.

Investing activities

For the year ended December 31, 2025, we spent $356.4 million on capital expenditures in conjunction with our development activities in which we drilled and brought online 23 gross operated wells and land and leasehold costs, and $61.2 million on deposits related to the Antero Acquisition. We also spent $12.6 million on other property and equipment largely related to midstream activities.

For the year ended December 31, 2024, we spent $249.5 million on capital expenditures in conjunction with our development activities in which we drilled and brought online 14 gross operated wells and land and leasehold costs. We also spent $6.6 million on other property and equipment largely related to midstream activities.

Financing activities

For the year ended December 31, 2025, the change in financing activity was primarily related to borrowing $253.5 million under our credit facility and repaying $362.0 of borrowings. We received approximately $286.5 million of funds associated with the IPO used in the repayment of borrowings.

For the year ended December 31, 2024, the change in financing activity was primarily related to borrowing $168.1 million under our prior credit facility and repaying $79.7 million of borrowings. We also paid approximately $5.2 million in syndication fees associated with the prior credit facility.

Analysis of Cash Flow Changes Between the Years Ended December 31, 2024 and 2023

Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in the 2024 Annual Report on Form 10-K filed with the SEC for a discussion of the cash flows for the year ended December 31, 2024 compared to the year ended December 31, 2023.

Derivative Activities

We are exposed to volatility in market prices and basis differentials for oil, natural gas and NGLs, which impacts the predictability of our cash flows related to the sale of those commodities. Accordingly, to achieve more predictable cash flow and reduce our exposure to adverse fluctuations in commodity prices, we use commodity derivatives, such as swaps, to hedge price risk associated with our anticipated production and to underpin our development program. This helps reduce potential negative effects of reductions in oil and gas prices but also reduces our ability to benefit from increases in oil and gas prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to utilize their value to further our strategic pursuits.

A fixed price swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A basis swap involves swapping variable interest rates based on different reference rates. We receive a fixed price differential and pays the floating market price differential to the counterparty which is calculated based on the differential between NYMEX and the natural gas price at a specific delivery point.

A put option has an established floor price. The buyer of that put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The following tables provide information about our derivative financial instruments as of December 31, 2025.

	Volume	Weighted Average Price	Fair Value as of December 31, 2025
Oil	*(in MBbls)*	*($ per Bbl)*	*(in thousands)*
Fixed price swaps			
2026	1,540	$ 64.06	$ 10,777
2027	97	$ 63.95	683
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	1,637		$ 11,460

Natural gas	Volume (in MMBtu)	Weighted Average Price ($ per MMBtu)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	50,726,000	$ 3.86	$ 16,467
2027	45,438,000	$ 3.94	1,969
2028	35,967,000	$ 3.77	917
2029	30,320,000	$ 3.62	194
2030	26,580,000	$ 3.57	(1,276)
2031	2,120,000	$ 4.08	(169)
Total	191,151,000		$ 18,102

Natural gas	Volume (in MMBtu)	Basis Differential ($ per MMBtu)	Fair Value as of December 31, 2025 (in thousands)
Basis swaps			
2026	53,439,000	$ (0.89)	$ (6,850)
2027	31,629,000	$ (0.64)	(1,717)
2028	32,603,750	$ (0.52)	(1,178)
2029	2,607,500	$ (0.30)	(78)
2030	—	$ —	—
2031	—	$ —	—
Total	120,279,250		$ (9,823)

Ethane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	8,604,000	$ 0.28	$ 282
2027	708,000	$ 0.30	14
2028	—	$ —	—
2029	—	$ —	–
2030	—	$ —	—
2031	—	$ —	—
Total	9,312,000		$ 296

Propane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	19,377,000	$ 0.71	$ 2,008
2027	1,524,000	$ 0.71	103
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	20,901,000		$ 2,111

Isobutane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	3,498,000	$ 0.84	$ 98
2027	276,000	$ 0.83	4
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	3,774,000		$ 102

Normal butane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	5,743,000	$ 0.82	$ 397
2027	455,000	$ 0.82	19
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	6,198,000		$ 416

Pentane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	2,487,000	$ 1.38	$ 553
2027	190,000	$ 1.34	39
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	2,677,000		$ 592

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(1) These natural gas basis swap contracts are settled based on the difference between Dominion South, REX Zone 3 or TETCO M2 price and the NYMEX price of natural gas during each applicable monthly settlement period.

Changes in the fair value of derivative contracts from December 31, 2024 to December 31, 2025, are presented below:

(in thousands)	Commodity Derivative Asset
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2024	$ (22,938)
Commodity hedge contract settlement payments, net of any receipts	(12,213)
Cash and non-cash mark-to-market gains on commodity hedge contracts (1)	58,407
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2025	$ 23,256

(1) At inception, new derivative contracts entered into by us have no intrinsic value.

Financing Agreements

Credit Facility

On September 25, 2024, we entered into a new credit facility led by Citibank, N.A. (the "Credit Facility"). The Credit Facility has a total facility size of $1.5 billion, subject to lender commitments and borrowing base limitations. As of December 31, 2025, our elected commitments and borrowing base were $375.0 million of which $150.9 million was outstanding. On February 23, 2026, in connection with the closing of the Antero Acquisition, we amended our Credit Facility to, among other things, increase the aggregate elected commitment amount from $375.0 million to $875.0 million and increase the borrowing base from $375.0 million to $875.0 million.

The Credit Facility replaced our prior credit facility (as defined below), which was terminated in connection with entry into the Credit Facility.

The Credit Facility also requires us to maintain compliance with the following financial ratios:

- Current ratio – the ratio of consolidated current assets (including an add back of unused commitments under the revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the Amended and Restated Credit Facility and non-cash derivative liabilities) of not less than 1.0 to 1.0 ; and
- Leverage ratio – the ratio of total funded debt to consolidated EBITDAX of not greater than 3.0 to 1.0 .

We were in compliance with the covenants and applicable financial ratios described above as of December 31, 2025.

Prior Credit Facility

On October 4, 2023, we entered into an amended and restated credit facility with a syndicate of banks led by the Bank of Oklahoma (the "prior credit facility"). Borrowings under our prior credit facility were subject to borrowing base limitations based upon the collateral value of the pledged assets and were subject to semi-annual redeterminations. The prior credit facility was scheduled to mature in April 2026, but was terminated on September 20, 2024, in connection with entry into the Credit Facility.

The prior credit facility also required us to maintain compliance with the following financial ratios:

- Current ratio – the ratio of consolidated current assets (including an add back of unused commitments under the revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the Amended and Restated Credit Facility and non-cash derivative liabilities) of not less than 1.0 to 1.0; and
- Leverage ratio – the ratio of total funded debt to consolidated EBITDAX of not greater than 3.0 to 1.0. We were in compliance with the covenants and applicable financial ratios described above as of December 31, 2023.

Other long-term debt

Other long-term debt principally relates to car loans associated with the Company's car fleet to support the Company's team to service and maintain its operated wells.

Payments due by fiscal year related to other long-term debt as of December 31, 2025, are as follows:

(in thousands)	Notes Payable
2026	$ 40
2027	15
2028	—
2029	—
2030	—
Total payments	$ 55

Critical Accounting Estimates

Our financial statements are prepared in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). In connection with preparing our financial statements, we are required to make assumptions and estimates about future events, and to apply judgments that affect the reported amounts of assets, liabilities, revenue, expense and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our financial statements are presented fairly and in accordance with U.S. GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in our audited financial statements included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report. Management believes that the following accounting estimates are those most critical to fully understanding and evaluating our reported financial results, and they require management's most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain.

Method of Accounting for Oil and Natural Gas Properties

We account for oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs, including non-productive costs and certain general and administrative costs such as salaries, benefits and other internal costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Under the full cost method of accounting, capitalized costs are amortized based on units-of-production and proved oil and natural gas reserves. If we maintain production levels year over year, our depreciation, depletion, and amortization expense may be significantly different if our estimates of remaining reserves or future development costs change significantly. On a quarterly basis, we review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC, which is referred to as a cost center ceiling test.

The primary factors impacting this test are reserve estimates and the unweighted arithmetic average of index prices on the first day of each month within the 12-month period that ends as of each quarterly balance sheet date. Downward revisions to estimates of oil and natural gas reserves and/or unfavorable prices may have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes (which our predecessor, INR Holdings, has not been subject to historically for federal income tax purposes), is generally written off as an expense. We did not record any impairment of oil and natural gas properties for years ended December 31, 2025 and 2024.

Additionally, costs associated with unevaluated properties are excluded from properties subject to amortization until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property at least annually for possible impairment. This assessment is subjective and includes consideration of numerous factors, including drilling plans, remaining lease terms, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. We did not record any impairment on our unevaluated properties for the years ended December 31, 2025 and 2024, but any such future impairment could potentially be material to our consolidated financial statements.

Oil and Natural Gas Reserves

Proved oil and gas reserves, as defined by SEC Regulation S-X, Rule 4-10, are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire unless evidence indicates that renewal is reasonably certain regardless of whether deterministic or probabilistic methods are used for the estimation.

Reserve estimates are prepared by independent engineers. Revisions may result from changes in, among other things, reservoir performance, development plans, prices, operating costs, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in certain proved reserves due to reaching economic limits sooner. A material change in the estimated volume of reserves could have an impact on the depletion rate calculation and our consolidated financial statements.

We estimate future net cash flows from natural gas, NGLs and oil reserves based on selling prices and costs using a 12-month average price, which is calculated as the unweighted arithmetic average of the first-day-of-the- month price for each month within the 12-month period and, as such, is subject to change in subsequent periods. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Income tax expense (which our predecessor, INR Holdings, was not subject to historically for federal income tax purposes for periods prior to the Corporate Reorganization) is based on currently enacted statutory tax rates and tax deductions and credits available under current laws.

Revenue Recognition

We derive revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. Our performance obligations are satisfied at a point in time and payments from purchasers are unconditional once the performance obligations have been satisfied, which occurs when control is transferred to the purchaser upon delivery of production volumes at a specified point. The pricing provisions of our contracts with customers are based on market indices, with certain adjustments for quality, supply and demand conditions, and location differentials, among other factors.

At the end of each month, we estimate the amount of production delivered to purchasers for that month and estimate revenues based on the price we expect to receive. Payments are generally received between 30 and 60 days after the date of production. Any variances between our accrued revenue estimates and the actual amounts of payments received for the sales of our production are recorded in the month that each payment is received from our purchasers. Such variances have historically not been significant.

The revenue derived from our midstream activities is generated from gathering assets owned by our wholly- owned subsidiary, INR Midstream. We charge a gathering fee per MMBtu transported through our gathering system and fees are recognized as revenue based on measured volumes at the specified delivery points when the associated service is performed.

Derivative Instruments

We use commodity derivatives for the purpose of mitigating the risk resulting from fluctuations in the market prices of crude oil and natural gas. We exercise significant judgment in determining the types of instruments to be used, the level of production volumes to include in our commodity derivative contracts, the prices at which we enter into commodity derivative contracts and counterparty creditworthiness. We do not use commodity derivative instruments for speculative or trading purposes.

We have not designated our derivative instruments as hedges for accounting purposes and, as a result, mark our derivative instruments to fair value and recognize the cash and non-cash change in fair value on derivative instruments for each period in the consolidated statements of operations. We are also required to recognize our derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation, and is generally determined using various inputs and assumptions including established index prices and other sources which are based upon, among other things, futures prices, time to maturity, implied volatilities and counterparty credit risk.

These fair values are recorded by netting asset and liability positions, including any deferred premiums, that are with the same counterparty and are subject to contractual terms which provide for net settlement. Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur.

Tax Receivable Agreement

As described in "Item 1. Business—Corporate Reorganization," Infinity Natural Resources entered into a Tax Receivable Agreement in connection with the closing of the IPO under which it is contractually committed to pay the Legacy Owners 85% of the net cash savings, if any, in U.S. federal, state and local income tax that Infinity Natural Resources (a) actually realizes with respect to taxable periods ending after the IPO or (b) is deemed to realize in the event of a change of control (as defined under the Tax Receivable Agreement, which includes certain mergers, asset sales and other forms of business combinations and certain changes to the composition of the INR board of directors) or the Tax Receivable Agreement terminates early (at our election or as a result of our breach) with respect to any taxable periods ending on or after such change of control or early termination event, in each case, as a result of (i) the tax basis increases resulting from the exchange of INR Units and the corresponding surrender of an equivalent number of shares of Class B common stock by the Legacy Owners for a number of shares of Class A common stock on a one-for-one basis or, at our option, the receipt of an equivalent amount of cash pursuant to the INR Holdings LLC Agreement and (ii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement.

The projection of future taxable income and utilization of tax attributes associated with the Tax Receivable Agreement involve estimates which require significant judgment. The amount of the Company's actual taxable income (which may differ from our estimates), passage of future legislation, or consummation of significant transactions in the future may significantly impact the liability related to the Tax Receivable Agreement. The Company will account for amounts payable under the Tax Receivable Agreement in accordance with Accounting Standard Codification Topic 450, *Contingencies*.

JOBS Act

The JOBS Act permits us, as an "emerging growth company," to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. We have elected to take advantage of this extended transition period, which means that the financial statements included in this Annual Report, as well as any financial statements that we file or furnish in the future, will not be subject to all new or revised accounting standards generally applicable to public companies for the transition period for so long as we remain an emerging growth company.

Recently Issued Accounting Standards

Refer to Note 2-Summary of Significant Accounting Policies, in Part II, Item 8. Financial Statements and Supplementary Data in this Annual Report for a discussion of recently issued accounting standards and their anticipated effect on our business.

Contractual Obligations and Commitments

We routinely enter into or extend operating and transportation agreements, office and equipment leases, drilling rig contracts, and other agreements, in the ordinary course of business. We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in consolidated debt or losses. The following table summarizes our obligations and commitments as of December 31, 2025, to make future payments under long-term contracts for the time periods specified below:

(in millions)	2026	2027	2028	2029	2030	Thereafter	Total
Credit Facility Principal[1]	$ —	$ —	$ 150.9	$ —	$ —	$ —	$ 150.9
Credit Facility Interest [2]	10.9	10.9	8.2	—	—	—	30.0

Asset Retirement Obligation	—	—	—	—	—	3.3	3.3
Other (3)	6.2	0.3	0.2	0.2	0.1	0.7	7.7
Total	$ 17.1	$ 11.2	$ 159.3	$ 0.2	$ 0.1	$ 4.0	$ 191.9

(1) This reflects borrowings outstanding under our Credit Facility as of December 31, 2025; Credit Facility borrowings may be repaid and reborrowed prior to maturity.
(2) This debt bears interest at the SOFR plus a borrowing spread. In determining future interest, we used outstanding amounts at December 31, 2025 and the average borrowing cost for calendar year 2025.
(3) This amount includes commitments from drilling rig contracts, vehicle notes, and operating leases.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Oil, Natural Gas and NGL Revenues

Our revenues and cash flows from operations are subject to many variables, the most significant of which is the volatility of commodity prices. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by global economic factors, pipeline capacity constraints, inventory levels, basis differentials, weather conditions and other factors. Commodity prices have long been volatile and unpredictable, and we expect this volatility to continue in the future.

There can be no assurance that commodity prices will not be subject to continued wide fluctuations in the future. A substantial or extended decline in such prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and gas reserves that may be economically produced, which could result in impairments of our oil and gas properties.

Commodity Price Risk and Hedges

Our primary market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Oil, natural gas and NGLs are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue for the foreseeable future. Our revenues, profitability and future growth are highly dependent on the prices we receive for our oil, natural gas and NGL sales, and the levels of our production, depend on numerous factors beyond our control, some of which are described in "Item 1A. Risk Factors."

Based on our production for the year ended December 31, 2024, our oil and gas sales for the year ended December 31, 2024 would have moved up or down $16.1 million for each 10% change in oil prices per Bbl, $5.1 million for each 10% change in gas prices per Mcf, and $4.5 million for each 10% change in NGL prices per Bbl. Based on our production for the year ended December 31, 2025, our oil and gas sales for 2025 would have moved up or down $17.4 million for each 10% change in oil prices per Bbl, $12.7 million for each 10% change in gas prices per Mcf, and $4.9 million for each 10% change in NGL prices per Bbl. These sensitivities are based on our 2024 and 2025 production volumes and average realized prices (before the effects of derivatives) for the respective periods.

Due to this volatility, we have historically used, and we may elect to continue to selectively use, commodity derivative instruments (such as collars, swaps, puts and basis swaps) to mitigate price risk associated with a portion of our anticipated production. Our derivative instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flows that can emanate from fluctuations in oil and natural gas prices, and thereby provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil and natural gas prices, but alternatively they partially limit our potential gains from future increases in prices. Our Credit Agreement limits our ability to enter into commodity hedges covering greater than 90% of our reasonably anticipated, projected production from proved properties. "Item 1A. Risk Factors" contains additional information regarding the volumes of our production covered by derivatives and the associated risks.

Counterparty and Customer Credit Risk

Our derivatives expose us to credit risk in the event of nonperformance by counterparties. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. We minimize the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; and (ii) only entering into hedging arrangements with counterparties that are also participants in the Credit Agreement, all of which have investment-grade credit ratings.

Our principal exposures to credit risk are through receivables resulting from the sales of our oil, natural gas, and NGLs. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit quality of our customers is high.

We sell our production to a relatively small number of customers, as is customary in our business. We extend and monitor credit based on an evaluation of their financial conditions and publicly available credit ratings. The future availability of a ready market for natural gas depends on numerous factors outside of our control, none of which can be predicted with certainty. For 2025, we had three customers that exceeded 10% of total revenues. We do not believe the loss of any single purchaser would materially impact our operating results as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Interest Rate Risk

As of December 31, 2025, our reserves supported a $375.0 credit facility of which $150.9 million in borrowings was outstanding leaving $224.1 million of unused capacity. Our largest exposure with respect to variable-rate debt comes from changes in the relevant benchmark rate underlying such debt financings, principally SOFR. We currently do not have an interest rate hedge program to hedge our exposure to floating interest rates on our variable-rate debt obligations. If annual interest rates increase 50 basis points, based on our December 31, 2024 and 2025, variable-rate debt, annual interest expense on variable-rate debt would increase by approximately $1.3 million and $0.8 million, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

INFINITY NATURAL RESOURCES, INC. AND SUBSIDIARIES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Infinity Natural Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Infinity Natural Resources, Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of operations, redeemable non-controlling interest and stockholders' / members' 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.

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 Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

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.

/s/ Deloitte & Touche LLP
Pittsburgh, Pennsylvania
March 10, 2026

We have served as the Company's auditor since 2024.

INFINITY NATURAL RESOURCES, INC. AND SUBSIDIARIES
Consolidated Balance Sheets
(*amounts in thousands*)

	December 31, 2025	December 31, 2024
Assets		
Current assets:		
Cash and cash equivalents	$ 2,849	$ 2,203
Accounts receivable:		
Oil and natural gas sales, net	54,836	39,314
Joint interest and other, net	12,912	32,229
Short Term Deposit on Acquisitions	61,200	—
Prepaid expenses and other current assets	4,002	11,822
Commodity derivative assets	24,838	—
Total current assets	$ 160,637	$ 85,568
Oil and natural gas properties, full cost method (including $88.7 million and $86.5 million as of December 31, 2025 and 2024, respectively excluded from amortization)	1,264,212	933,228
Midstream and other property and equipment	57,116	40,053
Less: Accumulated depreciation, depletion, and amortization	(256,712)	(153,233)
Property and equipment, net	$ 1,064,616	$ 820,048
Operating lease right-of-use assets, net	1,147	1,389
Deferred tax asset, net	4,858	—
Other assets	6,709	8,461
Commodity derivative assets	2,885	—
Total assets	$ 1,240,852	$ 915,466
Total Liabilities, Redeemable Interest and Stockholders' Equity / Members' Equity		
Current liabilities:		
Accounts payable	$ 38,572	$ 51,370
Royalties payable	39,686	23,129
Accrued liabilities and other	23,021	46,004
Operating lease liabilities	181	247
Commodity derivative liabilities, short-term	1,106	12,596
Total current liabilities	$ 102,566	$ 133,346
Credit facility borrowings	150,862	259,406
Operating lease liabilities, net of current portion	966	1,142
Asset retirement obligations	3,636	2,988
Commodity derivative liabilities	3,361	10,342
Tax Receivable Agreement	1,537	—
Total liabilities	$ 262,928	$ 407,224
Redeemable non-controlling interest	670,785	—
Stockholders' equity / members' equity		
Members' equity	—	508,242
Class A common stock—$0.01 par value; 400,000,000 shares authorized, 15,542,521 and 0 shares issued and outstanding as of December 31, 2025 and 2024, respectively	155	—
Class B common stock—$0.01 par value; 150,000,000 shares authorized, 45,247,974 and 0 shares issued and outstanding as of December 31, 2025 and 2024, respectively	452	—
Additional paid-in capital	310,972	—
Accumulated deficit	(4,440)	—
Total stockholders' equity / members' equity	307,139	508,242
Total liabilities, redeemable non-controlling interest and stockholders' equity / members' equity	$ 1,240,852	$ 915,466

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

INFINITY NATURAL RESOURCES, INC. AND SUBSIDIARIES
Consolidated Statements of Operations
(*amounts in thousands*)

	Year Ended December 31,		
	2025	2024	2023
Revenues:			
Oil, natural gas, and natural gas liquids sales	$ 350,375	$ 257,706	$ 159,532
Midstream activities	6,056	1,316	2,198
Total revenues	356,431	259,022	161,730
Operating expenses:			
Gathering, processing, and transportation	54,779	49,290	31,097
Lease operating	26,675	28,154	18,371
Production and ad valorem taxes	5,918	1,071	886
Depreciation, depletion, and amortization	103,751	73,726	53,796
General and administrative[(1)]	153,413	13,045	4,885
Total operating expenses	$ 344,536	$ 165,286	$ 109,035
Operating income	11,895	93,736	52,695
Other income (expense):			
Interest, net	(9,666)	(21,529)	(11,910)
Gain (loss) on derivative instruments	58,407	(22,047)	45,322
Other income (expense)	(1,535)	(874)	565
Net income before income tax expense (benefit)	59,101	49,286	86,672
Income tax expense (benefit)	(4,858)	—	—
Net income	$ 63,959	$ 49,286	$ 86,672
Net income attributable to Infinity Natural Resources, LLC prior to the reorganization	9,914	$ —	$ —
Net income attributable to redeemable non-controlling interests	40,209	$ —	$ —
Net income attributable to Infinity Natural Resources, Inc.	$ 13,836	$ —	$ —
Net income attributable to Infinity Natural Resources, Inc. per share of Class A common stock			
Basic:			
Weighted-average common stock outstanding	15,382,681	—	—
Net income attributable to Infinity Natural Resources, Inc.	0.90	—	—
Diluted:			
Weighted-average common stock outstanding	60,954,639	—	—
Net income attributable to Infinity Natural Resources, Inc.	0.89	—	—

(1) General and administrative expense includes a one-time share-based compensation expense of $126.1 million for the year ended December 31, 2025, incurred in connection with the IPO (as defined herein).

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

INFINITY NATURAL RESOURCES, INC. AND SUBSIDIARIES
Consolidated Statements of Redeemable Non-controlling Interest and Stockholders'/ Members' Equity
(*amounts in thousands, except share amounts*)

	INR Holdings Members' Equity	Class A Shares	Class A Amount	Class B Shares	Class B Amount	Additional Paid-in Capital	Accumulated deficit	Total	Redeemable Non-controlling Interest
Balance as of January 1, 2023	$ 149,506	—	$ —	—	$ —	$ —	$ —	$ —	$ —
Contributions	222,278	—	—	—	—	—	—	—	—
Net Income	86,672	—	—	—	—	—	—	—	—
Balance as of December 31, 2023	458,456	—	—	—	—	—	—	—	—
Contributions	500	—	—	—	—	—	—	—	—
Net Income	49,286	—	—	—	—	—	—	—	—
Balance as of December 31, 2024	$ 508,242	—	$ —	—	$ —	$ —	$ —	$ —	$ —
Net income prior to reorganization transactions	9,914	—	—	—	—	—	—	—	—
Effect of the reorganization transactions	(518,156)	—	—	45,638,889	456	—	—	456	517,700
Issuance of common stock in connection with initial public offering, net of underwriting discounts, commissions and other offering costs	—	15,237,500	152	—	—	198,204	—	198,356	76,911
Conversion of Class B Units to Class A Units	—	390,915	4	(390,915)	(4)	7,248		7,248	(7,248)
Share-based compensation plans	—	1,238	—	—	—	133,423	—	133,423	
Distributions to noncontrolling interest owners	—								(242)
Net income	—	—		—	—		13,836	13,836	40,209
Stock repurchase program	—	(87,132)	(1)	—	—	(1,187)	—	(1,188)	—
Increase in Tax Receivable Agreement Liability / Establishment of liabilities under the Tax Receivable Agreement	—	—	—	—	—	(1,537)	—	(1,537)	—
Adjustment of redeemable non-controlling interest to redemption value	—	—	—	—	—	(25,179)	(18,276)	(43,455)	43,455
Balance as of December 31, 2025	$ —	15,542,521	$ 155	45,247,974	$ 452	$ 310,972	$ (4,440)	$ 307,139	$ 670,785

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

INFINITY NATURAL RESOURCES, INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(*amounts in thousands*)

	Year Ended December 31,		
	2025	2024	2023
Cash flows from operating activities:			
Net income	$ 63,959	$ 49,286	$ 86,672
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	103,751	73,726	53,796
Amortization of debt issuance costs	1,705	1,957	778
Share-based compensation expense	133,423	—	—
Loss (gain) on derivative instruments	(58,407)	22,047	(45,322)
Cash received on settlement of derivative instruments	12,213	28,360	19,438
Non-cash lease expense	248	203	98
Deferred income taxes	(4,858)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	3,795	(27,447)	(21,775)
Prepaid expenses and other assets	(1,791)	143	(1,770)
Accounts payable	743	16,367	7,565
Royalties payable	16,557	5,554	6,390
Accrued and other expenses	(3,082)	11,776	703
Other assets and liabilities	(6,469)	(4,306)	(98)
Net cash provided by operating activities	$ 261,787	$ 177,666	$ 106,475
Cash flows from investing activities:			
Additions to oil and gas properties	(356,369)	(249,545)	(145,979)
Acquisitions of oil and gas properties	—	—	(278,967)
Deposits of acquisitions of oil and gas properties	(61,200)	—	—
Additions to midstream and other property and equipment	(12,598)	(6,573)	(11,740)
Net cash used in investing activities	$ (430,167)	$ (256,118)	$ (436,686)
Cash flows from financing activities:			
Borrowings under revolving credit facility	253,500	411,456	203,864
Borrowings on notes payable	124	—	—
Payments on revolving credit facility	(362,000)	(323,073)	(90,800)
Proceeds from issuance of Class A common stock in initial public offering, net of underwriting discounts and commissions	286,465	500	222,278
Payments of debt issuance costs	(645)	(5,200)	(4,256)
Payments of initial public offering costs	(6,760)	(4,415)	—
Payments on notes payable	(229)	(117)	(110)
Distributions to noncontrolling interest owners	(242)	—	—
Share Repurchase Program	(1,187)	—	—
Net cash provided by financing activities	$ 169,026	$ 79,151	$ 330,976
Net increase in cash and cash equivalents	646	699	765
Cash and cash equivalents at beginning of period	2,203	1,504	739
Cash and cash equivalents at end of period	$ 2,849	$ 2,203	$ 1,504

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

Note 1 – Description of the Business and Basis of Presentation

Description of Business. Infinity Natural Resources, Inc., together with its subsidiaries (collectively referred to as "Infinity", the "Company," "we," "our," or "us", unless the context otherwise indicates), was incorporated in the state of Delaware on May 15, 2024 in anticipation of a potential initial public offering and related reorganization transactions. The Company is an independent oil and natural gas exploration and production company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids ("NGLs"). Our operations are located in the Appalachian Basin in the northeastern United States.

Initial Public Offering. On January 30, 2025, the Company's registration statement on Form S-1 relating to its initial public offering ("IPO") was declared effective by the Securities and Exchange Commission ("SEC"), and the shares of its Class A common stock, par value $0.01 per share ("Class A common stock") began trading on the New York Stock Exchange ("NYSE") on January 31, 2025. The IPO closed in February 2025, pursuant to which the Company issued and sold 15,237,500 shares of its Class A common stock at a public offering price of $20.00 per share, including 1,987,500 shares issued pursuant to the full exercise of the underwriters' option to purchase additional shares. The Company received net proceeds of approximately $286.5 million, after deducting underwriting discounts and commissions of $18.3 million. The Company contributed the net proceeds of the IPO to Infinity Natural Resources, LLC ("INR Holdings"), and INR Holdings used the net proceeds, after payment of certain offering expenses, to repay borrowings outstanding under its revolving credit facility.

Corporate Reorganization. In connection with the IPO, we underwent a corporate reorganization whereby: (a) the membership interests of the existing owners (the "Legacy Owners") in INR Holdings were recapitalized into a single class of units (the "INR Units"), and, in exchange for their existing membership interests, the Legacy Owners received INR Units and an equal number of shares of the Company's Class B common stock, par value $0.01 per share ("Class B common stock"); and (b) we contributed the net proceeds of the IPO to INR Holdings in exchange for newly issued INR Units and a managing member interest in INR Holdings (the "Corporate Reorganization"). Pursuant to the Second Amended and Restated Limited Liability Company Agreement of INR Holdings (as amended, the "INR Holdings LLC Agreement"), holders of INR Units (other than INR) are entitled to exchange their INR Units, and surrender an equivalent number of shares of Class B common stock, for a number of shares of Class A common stock on a one-for-one basis or, at our option, the receipt of an equivalent amount of cash. As of December 31, 2025, we own an approximate 25.6% interest in INR Holdings and the Legacy Owners own an approximate 74.4% interest in INR Holdings.

The Company is a holding company whose sole material asset consists of membership interests in INR Holdings. The Company is the managing member of INR Holdings and controls all operational, management and administrative decisions relating to INR Holdings' business. Accordingly, the Company consolidates the financial results of INR Holdings and reports redeemable non-controlling interests in its consolidated financial statements related to the INR Units held by the Legacy Owners.

Basis of Accounting and Presentation. The consolidated financial statements present the financial position, results of operations, and cash flows of the Company in conformity with accounting principles generally accepted in the United States ("U.S. GAAP"). The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. All intercompany balances and transactions are eliminated upon consolidation. The consolidated financial statements include the accounts of the Company, its subsidiary INR Holdings, and INR Holding's wholly owned subsidiaries. Noncontrolling interests represent third-party ownership interests in INR Holdings and are presented as a component of equity. See Note 12 - "Stockholders' Equity and Noncontrolling Interest" for a discussion of noncontrolling interest.

Note 2 – Summary of Significant Accounting Policies

Use of Estimates. The preparation of financial statements 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. Management evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods it considers reasonable in the particular circumstances. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Estimates significant to our consolidated financial statements include the following:

- proved reserves used in calculating depletion;
- estimates of accrued revenues and unbilled costs;
- future cash flows from proved oil and natural gas reserves used in the impairment assessment;
- derivative financial instruments; and
- asset retirement obligations.

Cash and Cash Equivalents. We consider all highly liquid instruments with an original maturity of three months or less at the time of issuance to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short-term maturity of these investments. Interest earned on cash equivalents is included as a reduction of interest expense, net. We maintain cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits; however, we have not experienced any significant losses from such investments.

Commodity Derivative Financial Instruments. Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas we enter into commodity derivative contracts to protect against price declines in future periods. We have elected not to designate any of our commodity derivative instruments as cash flow hedges; therefore, these instruments do not qualify for hedge accounting. Accordingly, realized gains and losses from the settlement of commodity derivatives and unrealized gains and losses from changes in the fair value of remaining unsettled commodity derivatives are presented as a component of other income in the consolidated statements of operations. Management believes that presenting realized and unrealized gains and losses on commodity derivative instruments within revenues reflects the manner in which such instruments are economically linked to the Company's oil and natural gas production and sales. Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the consolidated balance sheet. We measure the fair value of our commodity derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors and nonperformance risk. See Note 9.

Deferred Offering Costs. Deferred offering costs incurred in connection with the Company's initial public offering were capitalized and offset against IPO proceeds upon completion of the offering in February 2025. As of December 31, 2024, deferred offering costs of $9.6 million were included in prepaid expenses and other current assets. No deferred offering costs were recorded as of December 31, 2025.

Accounts Receivable and Allowance for Expected Credit Losses. Accounts receivable consist of receivables from the sales of oil, natural gas, and NGL production delivered to purchasers and from joint interest owners on properties we operate. Accounts receivable are stated at the amount due, net of an allowance for expected losses as estimated by us when applicable. Most payments for accounts receivable are received within 30 to 60 days. We typically have the ability to withhold future revenue disbursements to recover any non-payment of joint interest accounts receivable from joint interest owners outstanding longer than the contractual payment terms are considered past due. As of December 31, 2025, 2024 and 2023, our allowances for credit losses were not material.

Drilling Advances. The Company participates in the drilling of crude oil and natural gas wells with other working interest owners. Due to the capital intensive nature of crude oil and natural gas drilling activities, the working interest owner responsible for conducting the drilling operations may request advance payments from other working interest owners for their share of the costs. The following table summarizes drilling advance receivables and deposits included in accounts receivable – other and accrued liabilities on the consolidated balance sheets as December 31, 2025 and 2024:

	For the Year Ended December 31,	
in thousands	2025	2024
Drilling Advance Receivable	$ 2,444	$ 12,502
Drilling Advance Deposits	$ 1,296	$ 6,188

Concentrations of Credit Risk. We are exposed to credit risk in the event of nonpayment by counterparties. We sell production to a relatively small number of customers, as is customary in our business. The table below summarizes the purchasers that accounted for 10% or more of our total revenues from the sale of commodities for the periods presented:

	For the Year Ended December 31,		
	2025	2024	2023
Marathon Oil Company	33%	55%	49%
BP America	35%	17%	28%
Ergon	16%	—%	—%
Blue Racer Midstream	—%	10%	13%

During these periods, no other purchaser accounted for 10% or more of our total commodity sales revenues. As of December 31, 2025, our accounts receivable balance related to oil and gas sales was comprised of amounts due from various purchasers, including amounts due from Marathon Oil Company, BP America and Ergon comprising 24%, 53% and 18%, respectively, of the total balance. As of December 31, 2024, our accounts receivable balance related to oil and gas sales was comprised of amounts due from Marathon Oil Company and BP America, which accounted for 49% and 25%, respectively, of the total balance.

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company also exposes itself to credit risk. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. We minimize the credit risk in derivative instruments by: (i) limiting our exposure to any single counterparty; and (ii) only entering into hedging arrangements with counterparties that are also participants in our credit agreement, all of which have investment-grade credit ratings.

Oil and Gas Properties

Oil and Natural Gas Properties. The Company uses the full cost method of accounting for its oil and natural gas properties. Accordingly, all costs directly associated with the acquisition, exploration, and development of oil, natural gas, and NGL reserves for both productive and nonproductive properties are capitalized into a full cost pool. Capitalized costs also include the costs of unproved properties and internal costs (i.e. salaries and benefits attributed to production activities of a well) directly related to the Company's acquisition, exploration, and development activities. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred.

Under the full cost method of accounting, total net capitalized costs of proved oil and natural gas properties may not exceed the ceiling limitation determined based on the estimated future net revenues of our proved reserves discounted at 10%. The future net revenues are estimated using the average of the first day of the month trailing 12-month price as of the period end date in accordance with guidance provided by the SEC, adjusted for basis or location differentials, held constant over the life of the proved reserves. A ceiling limitation calculation is performed at the end of each quarter. If the ceiling limitation is exceeded, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts members' equity and typically results in lower depletion expense in future periods. Once incurred, a write-down cannot be reversed at a later date. The Company did not have a ceiling test impairment for the years ended December 31, 2025, 2024 and 2023. See Note 4.

The costs associated with unproved properties are primarily the costs to acquire unproved acreage. Costs associated with unproved properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We review our unproved properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization. We also may capitalize interest on expenditures made in connection with bringing unproved properties to their intended use. We determine capitalized interest, when applicable, by multiplying our weighted-average borrowing cost on our revolving credit facility by the average amount of qualifying costs incurred that were excluded from the full cost pool; however, capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The following table represents our capitalized internal costs and interest shown within our oil and gas properties on the audited balance sheet for the years ended 2025, 2024 and 2023:

	For the Year Ended December 31,					
in thousands	2025		2024		2023	
Capitalized Internal Costs	$	7,558	$	5,612	$	2,238
Capitalized Interest Costs	$	—	$	41	$	—

Capitalized costs of proved properties are computed on a units-of-production basis based on estimated proved reserves, whereby the depletion rate is determined by dividing the total unamortized cost base plus future development costs by estimated proved reserves on a net equivalent basis at the beginning of the period. The depletion rate is multiplied by total production for the period to compute depletion expense. The following table shows our years ended 2025, 2024 and 2023 depletion expense related to oil and gas properties and average depletion rate per Boe:

	For the Year Ended December 31,					
in thousands	2025		2024		2023	
Depletion of Proved Oil and Natural Gas Properties	$	100,644	$	71,553	$	52,075
Average Depletion Rate per BOE	$	7.81	$	8.10	$	7.17

Unproved Property Impairment. The Company assesses properties excluded from the full cost pool. 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 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 the full cost ceiling test limitation. The Company did not have impairment on unproved properties for the years ended December 31, 2025, 2024 and 2023.

Midstream and Other Property and Equipment. Other property and equipment includes midstream assets, vehicles, furniture, fixtures, office equipment, and leasehold improvements, all of which are recorded at cost. These assets are depreciated using the straight-line method over their estimated useful lives which range between three and 25 years. Equipment upgrades and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts and a gain or loss is recorded in the consolidated statements of operations as needed. See Note 4.

Leases. At contract inception, we determine whether or not an arrangement contains a lease in accordance with the Financial Accounting Standards Board's (the "FASB") Accounting Standards Codification Topic 842, *Leases* ("ASC 842"). A contract is or contains a lease if it conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Upon determination that a contract meets the definition of a lease subject to ASC 842, a right-of-use asset and related lease liability are recorded based on the present value of the future lease payments over the lease term. Right-of-use assets represent our right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make future lease payments arising from the lease. Since the implicit rate in the lease is generally not available, we utilize our incremental borrowing rate as the discount rate for determining the present value of lease payments. See Note 6.

Asset Retirement Obligations. We accrue a liability for the estimated future costs associated with the plugging and abandonment of our oil and natural gas properties. For oil and natural gas wells, the fair value of our plugging and abandonment obligations is recorded at the time the obligation is incurred, which is typically at the time the well is spud. The fair value of the liability recognized is based on the present value of the estimated future cash outflows associated with our plugging and abandonment obligations. Revisions typically occur due to changes in estimated abandonment costs or the remaining lives of our wells, or if federal or state regulators enact new requirements regarding the abandonment of wells. We deplete the amount added to the costs of proved oil and natural gas properties and recognize an expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties. Accretion expense is included within depreciation, depletion, and amortization in the consolidated statements of operations. See Note 7.

Revenue Recognition. We derive revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when a performance obligation is satisfied by transferring control of the produced oil, natural gas, or NGLs to the customer. For all commodity products, we record revenue in the month production is delivered to the customer based on the amount of production delivered to the customer and the price we will receive. Payments are generally received between 30 and 60 days after the date of production. See Note 3.

Reportable Segment. We operate in only one reportable segment that is the exploration and production segment. All of our operations are conducted in one geographic area within the Appalachian Basin, primarily in Pennsylvania and Ohio, in the United States. See Note 17.

Income Taxes. The Company is subject to U.S. federal, state and local income taxes with respect to its allocable share of any taxable income of INR Holdings, as well as any stand-alone income generated by the Company. INR Holdings is treated as a partnership for U.S. federal and most applicable state and local income tax purposes. As a partnership, INR Holdings is not subject to U.S. federal and certain state and local income taxes. Any taxable income generated by INR Holdings is passed through to and included in the taxable income of its members, including the Company, on a pro rata basis.

Income taxes are recognized based on earnings reported for tax return purposes and provisions recorded for deferred income taxes. Deferred income tax assets and liabilities are recognized based on temporary differences resulting from: (i) net operating loss carryforwards for income tax purposes, and (ii) differences between the amounts recorded to the consolidated financial statements and the tax basis of assets and liabilities, as measured using enacted statutory tax rates in effect at the end of a period. The effect of a change in tax rates or tax laws is recognized in income during the period such changes are enacted. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized.

Adoption of New Accounting Standards

In December 2023, the FASB issued ASU 2023-09, *Income Taxes (Topic 740) – Improvements to Income Tax Disclosures* (“ASU 2023-09”), which requires that certain information in a reporting entity’s tax rate reconciliation be disaggregated and provides additional requirements regarding income taxes paid. The amendments are effective for annual periods beginning after December 15, 2024, with early adoption permitted, and should be applied either prospectively or retrospectively. The Company adopted this guidance effective upon becoming a public company in 2025.

In March 2024, the FASB issued ASU 2024-01, *Compensation-Stock Compensation (Topic 718)*. This ASU illustrates how to apply the scope guidance to determine whether a profits interest award should be accounted for as a share-based payment arrange under Accounting Standards Codification (“ASC”) 718 or another accounting standard. The amendments in this update are effective for public entities for fiscal years beginning after December 15, 2024. The Company adopted this guidance effective upon becoming a public company in 2025.

Accounting Standards Not Yet Adopted

In November 2024, the FASB issued ASU 2024-03 - Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40). This ASU requires entities to disaggregate any relevant expense caption presented on the face of the income statement within continuing operations into the following required natural expense categories within the footnotes, as applicable: (1) purchases of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, and (5) DD&A recognized as part of oil- and gas-producing activities or other depletion expenses. The amendments in this ASU are 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 adoption of this guidance.

We considered the applicability and impact of all ASUs. ASUs not listed above were assessed and determined to be either not applicable or not material upon adoption.

Note 3 – Revenues

Crude oil, natural gas, and NGL sales are recognized at the point in time when control of the product is transferred to the customer. Virtually all of our contract pricing provisions are based on market indices, with adjustments for transportation costs, quality differentials, and other contractual factors.

The following table presents commodity sales revenues from the sale of crude oil, natural gas, and NGLs:

	Year Ended December 31,		
	2025	2024	2023
(in thousands)			
Oil revenues	$ 173,612	$ 161,514	$ 85,276
Natural gas revenues	127,448	51,157	49,617
NGL revenues	49,315	45,035	24,639
Oil, natural gas, and natural gas liquids sales	$ 350,375	$ 257,706	$ 159,532

Oil Sales

Our crude oil sales contracts are generally structured whereby oil is delivered to the customer at a contractually agreed-upon delivery point. This delivery point is usually at the wellhead. Revenue is recognized when control transfers to the customer at the delivery point based on the net price received from the customer. Any downstream transportation or marketing costs incurred by purchasers of our crude oil are reflected in the price we receive and are presented as a net reduction to oil sales revenues.

Natural Gas and NGL Sales

Under our natural gas processing contracts, liquids rich natural gas is delivered to a midstream gathering and processing entity at an agreed upon delivery point. The midstream entity gathers and processes the raw gas and then remits proceeds to us. For these contracts, we evaluate when control of the residue gas and NGLs is transferred in order to determine whether revenues should be recognized on a gross or net basis. Where we elect to take its residue gas and/or NGL production "in-kind" at the plant tailgate, fees incurred prior to transfer of control at the outlet of the plant are presented as gathering, processing, and transportation expense within the consolidated statements of operations. Where we do not take our residue gas and/or NGL production "in-kind", transfer of control typically occurs at the inlet of the midstream entity's gas gathering system such that any fees incurred subsequent to the delivery point are reflected as a net reduction to natural gas and NGL revenues presented in the table above and as included within oil, natural gas, and natural gas liquids sales within the consolidated statements of operations. Accordingly, we recognizes revenues from natural gas and NGL sales on either a gross or net basis depending on when control of the commodity transfers to the customer under the applicable contract.

Performance Obligations

Our commodity sales contracts originate upon production and do not exist beyond each day's production. As a result, there are no remaining performance obligations under these contracts. Each delivery generally represents a separate performance obligation, and future volumes are wholly unsatisfied. Accordingly, disclosure of the transaction price allocated to remaining performance obligations is not required.

For all commodity products, we record revenue in the month production is delivered to the purchaser. Settlement statements for crude oil are generally received within 30 days following the date that production volumes are delivered, but for natural gas and NGL sales, statements may not be received for 30 to 60 days after delivery has occurred. However, payment is unconditional once the performance obligations have been satisfied. At such time, the volumes delivered and sales prices can be reasonably estimated and amounts due from customers are accrued in Accounts receivable – oil and natural gas sales, net in the consolidated balance sheets. As of December 31, 2025 and 2024, such receivable balances were $54.8 million and $39.3 million, respectively.

The Company is party to certain gathering service agreements that include minimum volume commitments ("MVCs"), which specify minimum quantities that the Company is required to deliver or pay for regardless of actual volumes gathered. Revenue related to MVCs is recognized when the related performance obligation has been satisfied, which occurs when the gas is gathered or when it becomes remote that the Company will meet the contractual minimum volume.

Note 4 – Property, Plant, and Equipment

Oil and Natural Gas Properties

We utilize the full cost method of accounting for costs related to the exploration, development, and acquisition of oil and natural gas properties. Our capitalized costs of oil and natural gas properties and the related accumulated depreciation, depletion, and amortization as of December 31, 2025 and 2024 are as follows:

(in thousands)	December 31, 2025	December 31, 2024
Oil and natural gas properties:		
Proved properties	$ 1,175,523	$ 846,738
Unproved properties	88,689	86,490
Gross oil and natural gas properties	1,264,212	933,228
Less: accumulated depreciation, depletion, and amortization	(249,296)	(148,638)
Oil and natural gas properties, net	$ 1,014,916	$ 784,590

In July 2024 we closed on approximately 5,705 net acres within Salt Fork State Park for $58.5 million, which was recorded to unproved leasehold properties.

Capitalized costs of oil and natural gas properties are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved oil, natural gas, and NGL reserves discounted at 10%. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, despite commodity price increases which subsequently increase the ceiling. Companies using the full cost method are required to use the unweighted average of the first-day-of-the-month prices for the preceding 12 months to calculate the ceiling value of reserves. Historically, we have not designated any of our derivative contracts as cash flow hedges. Prices used to calculate the ceiling value of reserves were as follows:

	For the Year Ended December 31,	
	2025	2024
Oil (per barrel)	$ 65.34	$ 75.48
Natural gas (per MMBtu)	$ 3.39	2.13
NGLs (per barrel)	$ 23.20	25.48

Using the average quoted prices above, adjusted for market differentials, the net book value of our oil and natural gas properties did not exceed the ceiling amount at December 31, 2025 or 2024. We had no derivative positions that were designated for hedge accounting as of and for the years ended December 31, 2025 and 2024. Future decreases in market prices, as well as changes in production rates, levels of reserves, evaluation costs excluded from amortization, future development costs and production costs may result in future non-cash impairments to our oil and natural gas properties.

Costs associated with unproved properties are excluded from the amortization base until the properties are evaluated or impairment is indicated. The costs associated with unproved leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value.

Our decision to exclude costs from amortization and the timing of the transfer of those costs into the amortization base involves judgment and may be subject to changes over time based on numerous factors, including drilling plans, availability of capital, project economics, and drilling results from adjacent acreage.

Costs of unproved properties excluded from amortization consist of leasehold acreage and relate to properties which are not individually significant for which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling, and other assessments. Therefore, we are unable to estimate when these costs will be included in the amortization computation.

Other Property and Equipment

Our other property and equipment consists of the following assets that are recorded at cost and depreciated on a straight-line basis over the respective estimated useful lives.

	December 31,	
	2025	2024
(in thousands)		
Midstream assets	$ 53,077	$ 36,880
Other property and equipment	4,039	3,173
Gross midstream and other property and equipment	57,116	40,053
Less: Accumulated depreciation	(7,416)	(4,595)
Total midstream and other property and equipment, net	$ 49,700	$ 35,458

The estimated useful lives of other property and equipment depreciated on a straight-line basis are as follows:

Midstream assets	5 – 25 years
Vehicles	5 years
Furniture, fixtures, and office equipment	3 – 10 years
Leasehold improvements	5 years

The carrying value of long-lived assets that are not part of our full cost pool are evaluated for recoverability whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Should an impairment exist, the impairment loss would be measured as the amount that the asset’s carrying value exceeds its fair value. We did not recognize any impairment during the years ended December 31, 2025 and 2024. Total depreciation expense for the years ended December 31, 2025 and 2024 totaled approximately $0.1 million and $2.1 million, respectively.

Note 5 – Accrued Liabilities and Other

Our accrued liabilities as of December 31, 2025 and December 31, 2024 consisted of the following amounts:

	December 31, 2025	December 31, 2024
Accrued capital expenditures	7,270	27,234
Accrued general and administrative expenses	7,706	3,293
JIB advance deposits	1,296	6,188
Other accrued liabilities	6,749	9,289
Total accrued liabilities	$ 23,021	$ 46,004

Note 6 – Leases

At contract inception, the Company determines whether or not an arrangement contains a lease in accordance with ASC 842. A contract is or contains a lease if it conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Upon determination that a contract meets the definition of a lease subject to ASC 842, a right-of-use asset and related lease liability are recorded based on the present value of the future lease payments over the lease term. Right-of-use assets represent the Company’s right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make future lease payments arising from the lease. Since the implicit rate in the lease is generally not available, the Company utilizes its incremental borrowing rate as the discount rate for determining the present value of lease payments. Right-of-use assets also include any lease payments made prior to commencement, excluding any lease incentives received.

We may enter into lease agreements for various purposes including drilling rig contracts, wellhead and surface equipment, rights-of-way and easements, and office space and equipment. For agreements that contain both lease and non-lease components, we have elected to combine and account for these as a single lease component. As of December 31, 2025, our lease agreements have remaining lease terms ranging from one month to 15 years; some of our agreements include options to extend the lease term and some of our agreements include options to early terminate at our sole discretion. These options are considered in determining the lease term and are included in the present value of future payments that are recorded for leases when we are reasonably certain to exercise the option. None of our lease agreements contain any material residual value guarantees or material restrictive covenants.

Leases with an initial term of 12 months or less are not recorded on the consolidated balance sheets. Lease expense for operating leases recorded on our consolidated balance sheets is recognized on a straight-line basis over the lease term. Variable lease payments for leases that are not recorded on our consolidated balance sheets are recognized in the period in which they are incurred, which primarily relate to our office space and equipment leases.

The following table provides additional information related to our lease right-of-use assets and liabilities as of December 31, 2025, 2024 and 2023:

	For the Year Ended December 31,		
	2025	2024	2023
Weighted-average discount rate	9.0%	9.0%	9.1%
Weighted-average remaining lease term (years)	9.7	9.4	13.0

For the years ended December 31, 2025, 2024 and 2023, lease expense, including operating leases related to our office space, of $0.4 million, $0.3 million and $0.2 million, respectively, was included within general and administrative expenses within our consolidated statements of operations.

Payments due under our long-term operating lease liabilities by fiscal year as of December 31, 2025, are as follows:

(in thousands)	Operating Leases
2026	$ 277
2027	277
2028	221
2029	185
2030	91
Thereafter	705
Total lease payments	1,756
Less: imputed interest	(609)
Present value of lease liabilities	$ 1,147

Note 7 – Asset Retirement Obligations

	December 31,	
(in thousands)	2025	2024
Asset retirement obligations, beginning of period	$ 2,988	$ 970
Liabilities assumed in leasehold acquisitions	121	—
Liabilities incurred	389	87

Liabilities settled	(150)	(10)
Accretion expense	268	101
Revision to estimated cash flows	20	1,840
Asset retirement obligations, end of period	$ 3,636	$ 2,988

An asset retirement obligation represents a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within our control. The liability is initially measured as the present value of the estimated future costs associated with plugging and abandonment of oil and natural gas wells and other equipment removal, and land restoration activities. Upon initially recognizing the liability, the Company capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period through accretion expense and the capitalized cost is depleted over the units-of-production method as part of the full cost pool. Accretion expense is included as part of depreciation, depletion, and amortization in the consolidated statements of operations.

Inherent in the fair value calculation of asset retirement obligations are numerous estimates and assumptions including plugging and abandonment settlement amounts, inflation rates, credit-adjusted risk-free rates, and the timing of settlement. Asset retirement obligations incurred in the current period were Level 3 fair value measurements as the inputs used to measure the fair value are unobservable. During 2025, the Company recorded changes in estimates attributable primarily to changes in working interest. During 2024, the Company recorded changes in estimates attributable primarily to increased plugging costs.

Note 8 – Debt

On September 25, 2024, INR Holdings entered into a credit facility led by Citibank, N.A. (the “Credit Facility” and the credit agreement governing the Credit Facility, as amended, the “Credit Agreement”) with a syndicate of financial institutions with an initial aggregate elected commitment amount and initial borrowing base of $325.0 million. On March 31, 2025, the Company amended the Credit Agreement to, among other things, increase each of the aggregate elected commitment amount and borrowing base from $325.0 million to $350.0 million. On May 29, 2025, the Company amended the Credit Agreement to, among other things, amend certain provisions relating to hedging requirements and restrictions in the Credit Agreement. Effective October 1, 2025, the borrowing base under the Credit Facility was increased from $350.0 million to $375.0 million and the aggregate elected commitment amount was also increased from $350.0 million to $375.0 million.

On December 5, 2025, INR Holdings entered into that certain Third Amendment to Credit Agreement, which among other things, amended certain provisions relating to hedging requirements and restrictions, debt incurrences and permitted acquisitions in the Credit Agreement. The borrowing base is based on the net present value of our oil and gas properties and is subject to semi-annual redeterminations. The Credit Facility is guaranteed by INR Holdings’ subsidiaries and is secured by first priority security interests on substantially all of INR Holdings’ consolidated assets.

Borrowings under the Credit Facility may be base rate loans or Secured Overnight Financing Rate (“SOFR”) loans. Base rate loans bear interest at a rate per annum equal to the greater of: (i) the administrative agent bank’s prime rate; (ii) the federal funds effective rate plus 50 basis points; or (iii) the adjusted Term SOFR rate (as defined in the Credit Agreement), plus an additional basis point credit spread, plus an applicable margin ranging from 275 basis points to 375 basis points, depending on the percentage of the borrowing base utilized. SOFR loans bear interest at SOFR plus an applicable margin ranging from 275 basis points to 375 basis points, depending on the percentage of the borrowing base utilized, plus an additional basis point credit spread. We also pay a commitment fee on unused elected commitment amounts under the Credit Facility, which is also dependent on the percentage of the borrowing base utilized. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for SOFR loans. The Credit Facility matures in September 2028. As of December 31, 2025, the Company’s reserves supported a $375.0 million borrowing base of which $150.9 million was outstanding, leaving $224.1 million of unused capacity.

For the years ended December 31, 2025 and 2024, total interest expense on the Credit Facility was $7.8 million and $19.1 million, respectively. We did not capitalize any interest expense for the years ended December 31, 2025 and 2024. For the years ended December 31, 2025 and 2024, the Company’s weighted-average interest rate was 7.2% and 8.3%, respectively.

Debt issuance costs associated with the Credit Facility are capitalized and presented as other assets within the unaudited condensed consolidated balance sheets. Debt issuance costs are amortized using the straight-line method over the term of the related agreement. We capitalized an additional $1.1 million of debt issuance costs related to the Credit Facility for the year ended December 31, 2025. As of December 31, 2025 and December 31, 2024, capitalized debt issuance costs were approximately $6.7 million and $7.9 million, respectively. Amortization of debt issuance costs, which is included within interest expense in the consolidated statements of operations, was approximately $2.3 million and $2.4 million for the years ended December 31, 2025 and 2024, respectively.

The Credit Facility also requires INR Holdings to maintain compliance with financial ratios including a current ratio of not less than 1.0 to 1.0 and a leverage ratio no greater than 3.0 to 1.0, each of which is defined within the terms of the Credit Agreement. INR Holdings is in compliance with the covenants and financial ratios under the Credit Agreement described above through the date these audited consolidated financial statements were available to be issued.

Other Long-Term Debt

Other long-term debt principally relates to car loans associated with our car fleet to support service and maintenance of our operated wells.

Payments due by fiscal year related to other long-term debt as of December 31, 2025 are as follows:

(in thousands)	Notes Payable
2026	$ 40
2027	15
2028	—
2029	—
2030	—
Total payments	$ 55

Note 9 – Derivatives and Risk Management

We are exposed to volatility in market prices and basis differentials for oil, natural gas, and NGLs, which impacts the predictability of our cash flows related to the sale of those commodities. The overall objective of our hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices, which we do by using various derivative instruments including fixed price swaps, basis swaps, and collars. As a result of our hedging activities, we may realize prices that are greater or less than the market prices that we would have otherwise received.

We typically enter into over the counter (OTC) derivative contracts with financial institutions and regularly monitor the creditworthiness of all counterparties. Certain of our hedging arrangements are with counterparties that are also lenders (or affiliates of lenders) under our Credit Facility. As of December 31, 2025, we did not have any cash or letters of credit posted as collateral for our derivative financial instruments.

We do not designate any of its derivative instruments as cash flow hedges; therefore, all changes in fair value of our derivative instruments are recognized in other income within the consolidated statements of operations. We recognize all derivative instruments as either assets or liabilities at fair value within the consolidated balance sheets, subject to master netting arrangements that permit the net settlement of derivative assets and liabilities.

Contracts that result in physical delivery of a commodity expected to be sold by us in the normal course of business are generally designated as normal purchases and normal sales and are exempt from derivative accounting. Contracts that result in the physical receipt or delivery of a commodity but are not designated or do not meet all of the criteria to qualify for the normal purchase and normal sale scope exception are subject to derivative accounting.

The following tables provide information about our derivative financial instruments. The tables present the notional amount, the weighted average contract prices and the fair values by expected maturity dates as of December 31, 2025.

Oil	**Volume** *(in MBbls)*	**Weighted Average Price** *($ per Bbl)*	**Fair Value as of December 31, 2025** *(in thousands)*
Fixed price swaps			
2026	1,540	$ 64.06	$ 10,777
2027	97	$ 63.95	683
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	1,637		$ 11,460

Natural gas	**Volume** *(in MMBtu)*	**Weighted Average Price** *($ per MMBtu)*	**Fair Value as of December 31, 2025** *(in thousands)*
Fixed price swaps			
2026	50,726,000	$ 3.86	$ 16,467
2027	45,438,000	$ 3.94	1,969
2028	35,967,000	$ 3.77	917
2029	30,320,000	$ 3.62	194
2030	26,580,000	$ 3.57	(1,276)
2031	2,120,000	$ 4.08	(169)
Total	191,151,000		$ 18,102

Natural gas	**Volume** *(in MMBtu)*	**Basis Differential** *($ per MMBtu)*	**Fair Value as of December 31, 2025** *(in thousands)*
Basis swaps			
2026	53,439,000	$ (0.89)	$ (6,850)
2027	31,629,000	$ (0.64)	(1,717)
2028	32,603,750	$ (0.52)	(1,178)
2029	2,607,500	$ (0.30)	(78)
2030	—	$ —	—
2031	—	$ —	—
Total	120,279,250		$ (9,823)

Ethane	**Volume** *(in gallons)*	**Weighted Average Price** *($ per gallon)*	**Fair Value as of December 31, 2025** *(in thousands)*
Fixed price swaps			
2026	8,604,000	$ 0.28	$ 282
2027	708,000	$ 0.30	14
2028	—	$ —	—

2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	9,312,000		$ 296

Propane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	19,377,000	$ 0.71	$ 2,008
2027	1,524,000	$ 0.71	103
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	20,901,000		$ 2,111

Isobutane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	3,498,000	$ 0.84	$ 98
2027	276,000	$ 0.83	4
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	3,774,000		$ 102

Normal butane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	5,743,000	$ 0.82	$ 397
2027	455,000	$ 0.82	19
2028	—	$ —	—
2029	—	$ —	—
2030	—	$ —	—
2031	—	$ —	—
Total	6,198,000		$ 416

Pentane	Volume (in gallons)	Weighted Average Price ($ per gallon)	Fair Value as of December 31, 2025 (in thousands)
Fixed price swaps			
2026	2,487,000	$ 1.38	$ 553

2027	190,000	$	1.34	39
2028	—	$	—	—
2029	—	$	—	—
2030	—	$	—	—
2031	—	$	—	—
Total	2,677,000			$ 592

Derivative assets and liabilities are presented below as gross assets and liabilities, without regard to master netting arrangements, which are considered in the presentation of derivative assets and liabilities in the accompanying balance sheets.

The following table summarizes the gross fair value of our derivative assets and liabilities and the effect of netting as of December 31, 2025 and 2024:

	December 31, 2025		
Balance Sheet Classification	**Gross Amounts**	**Netting Adjustment**	**Net Amounts Presented on Balance Sheet**
(in thousands)			
Assets			
Commodity derivative assets, short-term	$ 32,718	$ (7,880)	$ 24,838
Commodity derivative assets, long-term	7,701	(4,816)	2,885
Total assets	$ 40,419	$ (12,696)	$ 27,723
Liabilities			
Commodity derivative liabilities, short-term	$ 8,986	$ (7,880)	$ 1,106
Commodity derivative liabilities, long-term	8,177	(4,816)	3,361
Total liabilities	$ 17,163	$ (12,696)	$ 4,467

	December 31, 2024		
Balance Sheet Classification	**Gross Amounts**	**Netting Adjustment**	**Net Amounts Presented on Balance Sheet**
(in thousands)			
Assets			
Commodity derivative assets, short-term	$ 6,089	$ (6,089)	$ —
Commodity derivative assets, long-term	2,647	(2,647)	—
Total assets	$ 8,736	$ (8,736)	$ —
Liabilities			
Commodity derivative liabilities, short-term	$ 18,685	$ (6,089)	$ 12,596
Commodity derivative liabilities, long-term	12,989	(2,647)	10,342
Total liabilities	$ 31,674	$ (8,736)	$ 22,938

Our total derivative gains and losses for the years ended December 31, 2025, 2024 and 2023 were as follows:

	For the Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Realized gain on derivative instruments	$ 12,213	$ 28,360	$ 19,438
Unrealized gain (loss) on derivative instruments	46,194	(50,407)	25,884
Total gain (loss) on derivative instruments	$ 58,407	$ (22,047)	$ 45,322

Note 10 – Fair Value Measurements

Certain of our assets and liabilities are measured at fair value. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In determining fair value, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique.

The carrying values of cash and cash equivalents, including accounts receivable, other current assets, accounts payable and other current liabilities approximate fair value due to their short-term nature. The carrying value of outstanding borrowings under the Credit Facility approximates fair value because the interest rates are variable and reflective of market rates. The estimated fair value of borrowings under the Credit Facility would be categorized as a Level 2 measurement within the fair value hierarchy.

We follow ASC Topic 820, *Fair Value Measurement* ("ASC 820"), which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets (other than quoted prices included within Level 1), and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs - inputs to the valuation methodology are unobservable but should reflect the assumptions that market participants would use when pricing the asset or liability, including assumptions about risk (consistent with the fair value measurement objective).

Recurring Fair Value Measurements

The following table presents, for each applicable level within the fair value hierarchy, our net derivative assets and liabilities, including both current and noncurrent portions, measured at fair value on a recurring basis.

	December 31, 2025			
(in thousands)	Level 1	Level 2	Level 3	Fair Value
Assets				
Fixed price swaps	$ —	$ 33,079	$ —	$ 33,079
Basis swaps	—	349	—	349
Liabilities				
Fixed price swaps	—	—	—	—
Basis swaps	—	(10,172)	—	(10,172)
Total	$ —	$ 23,256	$ —	$ 23,256

	December 31, 2024			
	Level 1	Level 2	Level 3	Fair Value
(in thousands)				
Assets				
Fixed price swaps	$ —	$ 4,012	$ —	$ 4,012
Basis swaps	—	—	—	—
Liabilities				
Fixed price swaps	—	(13,685)	—	(13,685)
Basis swaps	—	(13,263)	—	(13,263)
Total	$ —	$ (22,938)	$ —	$ (22,938)

Derivative assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. We have classified our derivative instruments into levels depending upon the data utilized to determine their fair values. The Company uses industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied market volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data. As such, the Company classifies the fair value of its commodity derivative contract within Level 2 of the fair value hierarchy.

Nonrecurring Fair Value Measurements

Certain assets and liabilities are measured at fair value on a nonrecurring basis in certain circumstances. These assets and liabilities can include asset retirement obligations when incurred and other long-lived assets that are written down to fair value when they are impaired. The Company did not record any impairment charge related to these assets and liabilities for the years ended December 31, 2025 and December 31, 2024.

Note 11 – Income Taxes and Tax Receivable Agreement

Tax Provision. As a result of the IPO and related Corporate Reorganization, Infinity became the sole managing member of INR Holdings, which is treated as a partnership for U.S. federal and certain state and local income tax purposes. As a partnership, INR Holdings is not subject to U.S. federal income tax at the entity level. Instead, taxable income or loss generated by INR Holdings is allocated to its members, including the Company, and is reported on the respective tax returns of those members.

Our predecessor, INR Holdings, is a limited liability company treated as a partnership for U.S. federal income tax purposes and, therefore, has not been subject to U.S. federal income tax at an entity level. As a result, the consolidated net income (loss) in our historical financial statements for periods prior to the IPO and Corporate Reorganization does not reflect the tax expense (benefit) we would have incurred if we were subject to U.S. federal income tax at an entity level during those periods.

Beginning with the IPO, the Company is subject to U.S. federal income taxes and state and local income taxes with respect to its allocable share of taxable income or loss of INR Holdings, as well as any stand-alone income or loss generated at the Company level. Prior to the IPO and Corporate Reorganization, INR Holdings operated as a limited liability company treated as a partnership for U.S. federal income tax purposes and was not subject to U.S. federal income tax at the entity level. As a result, the consolidated net income (loss) in the historical financial statements for periods prior to the IPO does not reflect the income tax expense (benefit) that would have been incurred if the Company had been subject to U.S. federal income tax during those periods.

	Year Ended December 31,		
	2025	**2024**	**2023**
Current tax expense (benefit)			
Federal	$ —	$ —	$ —
State	$ —	$ —	$ —
Total current tax expense (benefit)	$ —	$ —	$ —
Deferred tax expense (benefit)			
Federal	$ (4,668)	$ —	$ —
State	$ (190)	$ —	$ —
Total deferred tax expense (benefit)	$ (4,858)	$ —	$ —
Total income tax expense (benefit)	$ (4,858)	$ —	$ —

Effective Tax Rate. The Company's overall effective tax rate differs from the U.S statutory rate primarily due to the fact that prior to the IPO, INR Holdings was structured as a partnership for U.S. federal income tax and subsequent to the IPO, the income (loss) attributable to the non-controlling interests in INR Holdings is not subject to U.S. federal income tax at the Company or INR Holdings. In addition, the Company reduced its valuation allowance with respect to investment in INR Holdings as discussed further below. As a result of the Company’s Up-C organizational structure, the allocation of income to non-controlling interests, and valuation allowance activity, the Company’s effective tax rate for the year ended December 31, 2025 is not indicative of the effective tax rate that may be expected in future periods.

In connection with the IPO, the Company recorded a deferred tax asset of $16.8 million resulting from its purchase of INR Units in INR Holdings. The deferred tax asset results from the difference between the Company's outside basis in its investment in INR Holdings compared to its share of the net financial statement carrying value of the assets of INR Holdings. At the time of the IPO, we determined that the deferred tax asset associated with the investment in INR Holdings was not more likely than not to be realized and recorded a valuation allowance of $16.8 million. The initial deferred tax asset of $16.8 million for the investment in INR Holdings and the related valuation allowance of $16.8 million are recorded against additional paid-in capital in the condensed consolidated statements of redeemable non-controlling interest and stockholders’ / members’ equity.

During the year ended December 31, 2025, the Company’s taxable income attributable to its interest in INR Holdings was lower than its share of book income, which reduced the Company’s deferred tax asset related to its investment in INR

Holdings. As a result, a corresponding reduction in the valuation allowance was recorded through income tax benefit in the consolidated statements of operations.

The reconciliation of income taxes at the federal statutory level to provision for income taxes is as follows:

	Year Ended December 31,									
	2025			2024			2023			
	$		%	$		%	$		%	
U.S. federal tax expense (benefit) at statutory rate	$	12,429	21 %	$	—	21 %	$	—	21 %	
State tax, net of federal benefit	$	(150)	— %	$	—	— %	$	—	— %	
Pre-Offering non-taxable/deductible income	$	24,407	41 %	$	—	— %	$	—	— %	
Non-controlling interests	$	(27,520)	(47)%	$	—	— %	$	—	— %	
IPO Underwriting Fees	$	—	— %	$	—	— %	$	—	— %	
Non-Deductible expenses	$	291	1 %	$	—	— %	$	—	— %	
Percentage Depletion	$	(575)	(1)%	$	—	— %	$	—	— %	
Change in Valuation Allowance	$	(13,741)	(23)%	$	—	— %	$	—	— %	
Total income tax expense (benefit)	$	(4,858)	(8)%	$	—	21 %	$	—	21 %	

Deferred Tax Assets and Liabilities. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts and income tax basis of assets and liabilities and the expected benefits of utilizing net operating losses and other tax carryforwards, using enacted tax rates in effect for the taxing jurisdictions in which the Company operates for the year in which those temporary differences are expected to be recovered or settled.

The tax effects of each temporary difference and carryforward as of December 31, 2025 and December 31, 2024 are as follows:

	Year Ended December 31,			
	2025		**2024**	
Deferred tax assets:				
Net operating losses	$	4,054	$	—
Investment in partnership	$	2,298	$	—
Disallowed depletion carryforward	$	804	$	—
Total deferred tax assets:	$	7,157	$	—
Deferred tax liabilities:				
Valuation allowance	$	(2,298)	$	—
Net deferred tax asset (liabilities)	$	4,858	$	—

The Company evaluates all deferred tax assets as to their future realization using positive and negative evidence. As of December 31, 2025, the Company has recorded a full valuation allowance against its deferred tax asset associated with its investment in INR Holdings. The Company carries a deferred tax asset on its net operating losses at the federal and Pennsylvania level. These net operating losses do not expire. The Company has determined that it is more likely than not to realize all of the tax benefits associated with its net operating losses due to the lack of expiration of the net operating losses, positive book income in 2025, and projected income in future years.

During the year ended December 31, 2025, members of INR Holdings redeemed 0.4 million INR Holdings Units (together with the cancellation of 0.4 million shares of Class B common stock) for an equivalent number of shares of Class A common stock. As a result of this redemption, there was minimal change in the Company's deferred tax asset position. Because the deferred tax change arose in connection with a transaction between the Company and stockholders, the initial change in deferred tax asset, as well as the impact on the Company's valuation allowance, is recorded in additional paid-in capital in the condensed consolidated statements of redeemable non-controlling interest and stockholders' / members' equity.

The Company evaluates uncertain tax positions for recognition and measurement in the financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the financial statements. As of December 31, 2025, the Company has no significant uncertain tax positions.

The Company files income tax returns in the U.S. federal jurisdiction and Pennsylvania on a separate basis. There are currently no federal or state income tax examinations underway for these jurisdictions. The Company's federal and state returns remain open to examination for tax years 2024 and 2025.

Taxes Paid by Jurisdiction. For the years ended December 31 2025, 2024 and 2023, neither INR Holdings nor the Company paid any entity level U.S. federal, state or foreign income taxes.

Tax Receivable Agreement. We entered into the TRA with the Legacy Owners in connection with the IPO. This agreement generally provides for the payment by us to the Legacy Owners of 85% of the net cash savings, if any, in U.S. federal, state and local income tax that we (a) actually realize with respect to taxable periods ending after the IPO or (b) are deemed to realize in the event of a change of control (as defined under the TRA, which includes certain mergers, asset sales and other forms of business combinations and certain changes to the composition of our board of directors) or the TRA terminates early (at our election or as a result of our breach) with respect to any taxable periods ending on or after such change of control or early termination event, in each case, as a result of (i) the tax basis increases resulting from the exchange of INR Units and the corresponding surrender of an equivalent number of shares of Class B common stock by the Legacy Owners for a number of shares of Class A common stock on a one-for-one basis or, at our option, the receipt of an equivalent amount of cash pursuant to the INR Holdings LLC Agreement and (ii) deductions arising from imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. We will retain the benefit of the remaining 15% of these cash savings, if any.

On August 15, 2025 a Legacy Owner redeemed 390,915 INR Units for shares of Class A common stock on a one-for-one basis. Concurrently with the redemption of the INR Units, an equal number of shares of Class B common stock were cancelled. The Company recognizes a liability for the estimated amounts payable under the TRA when it is probable that taxable income will be sufficient to realize the related tax benefits and the amounts can be reasonably estimated. The estimation of liability under the TRA is by its nature imprecise and subject to significant assumptions regarding the amount, character, and timing of the taxable income of the Company in the future. Changes in tax laws or rates could also materially impact the estimated liability. As of December 31, 2025, the Company recorded a TRA liability of $1.5 million, all of which has been classified as a non-current liability.

Note 12 – Stockholders' Equity and Noncontrolling Interest

Predecessor Members' Equity

Prior to the Corporate Reorganization, INR Holdings had two classes of equity in the form of Class A and Class B interests, and non-voting, performance-based incentive units ("Incentive Units") that were issued to certain members of management. Profits and losses for both Class A and Class B interests were determined and allocated among each equity interest holder in a manner such that the adjusted capital account of each equity interest holder was as nearly as possible equal to the distributions that would have been made to such equity interest holder if certain transactions occurred based on each equity interest holders proportionate ownership interest.

Distributions to holders of Class A interests, Class B interests and Incentive Units were made in accordance with the INR Holdings Amended and Restated Limited Liability Company Agreement (as amended, the "Amended and Restated LLC Agreement"), which were provided first to holders of Class A interests and then to Class B interests. Distributions to holders of Incentive Units were made upon the occurrence of each respective Incentive Unit Tier's Payout per each respective Incentive Unit Tier (each as defined in the Amended and Restated LLC Agreement).

At the time of the Corporate Reorganization, Class A interests, Class B interests, and Incentive Units were issued and outstanding. As a result of the Corporate Reorganization, all Class A interests, Class B interests, and Incentive Units were exchanged for INR Units and an equal number of shares of Class B common stock, and no Class A interests, Class B interests, or Incentive Units remain issued or outstanding.

Stockholders' Equity

As a result of the Corporate Reorganization, the membership interests of the Legacy Owners in INR Holdings were recapitalized into INR Units, and, in exchange for their existing membership interests, the Legacy Owners received 45,638,889 INR Units and an equal number of shares of our Class B common stock. We contributed the net proceeds of the IPO to INR Holdings in exchange for 15,237,500 newly issued INR Units and a managing member interest in INR Holdings. We own an approximate 74.4% interest in INR Holdings and the Legacy Owners own an approximate 25.6% interest in INR Holdings.

As of December 31, 2025, the Company's equity structure consists of Class A common stock and Class B common stock. Each share of Class A common stock entitles its holder to one vote per share and the right to receive dividends and other distributions when, as, and if declared by our board of directors. Class A stockholders are also entitled to share in any assets remaining upon liquidation, after satisfaction of all debts and liabilities. Holders of Class A common stock do not have preemptive or conversion rights. The Class A common stock is economically entitled to the results of operations of the Company, through its ownership interest in INR Holdings.

Each share of Class B common stock entitles its holder to one vote per share on matters submitted to the Company's stockholders but does not provide the holder with economic rights. Class B common stockholders do not participate in dividends or other distributions and have no rights to Company assets upon liquidation. Each share of Class B common stock is paired with one INR Unit and is cancellable upon exchange or redemption of the corresponding INR Unit for one share of Class A common stock or, at our option, the receipt of an equivalent amount of cash. INR Units represent economic interests in INR Holdings.

Distributions by INR Holdings, if any, are made to the holders of INR Units on a pro rata basis, subject to applicable law and the INR Holdings LLC Agreement. Distributions, if any, are expected to be made to fund the Company's payment of taxes, payments under the TRA, any dividends declared on Class A common stock, and other corporate purposes.

As of December 31, 2025, the Company consolidates the financial results of INR Holdings in its consolidated financial statements. The portion of net income and equity attributable to the INR Units held by the Legacy Owners is reported as a redeemable non-controlling interest within mezzanine equity in the consolidated financial statements.

Note 13 – Share-based Compensation

INR Holdings Incentive Plan

In connection with the closing of the IPO, INR Holdings' members elected to accelerate the vesting of certain Incentive Units. The Incentive Units were originally issued by INR Holdings and were accounted for under ASC 710. As a result of the acceleration, all unvested Incentive Units vested and were recapitalized into INR Units at a valuation of $20.00 per unit, which reflects the IPO price of the Company's Class A common stock. This recapitalization resulted in the recognition of $126.1 million of non-recurring compensation expense for the year ended December 31, 2025 and is recorded within the consolidated statement of operations as a component of General and administrative.

Omnibus Incentive Plan

In connection with the IPO, the Company adopted the Infinity Natural Resources, Inc. Omnibus Incentive Plan (the "Plan"). The Plan provides for the grant of stock-based awards to the Company's employees, non-employee directors, and consultants, including restricted stock units ("RSUs"), performance stock units ("PSUs"), stock options, stock appreciation rights, restricted stock, dividend equivalent rights and other stock or stock-based awards. An aggregate of 5,888,889 shares of Class A common stock have been reserved for issuance under the Plan, subject to adjustments for stock splits, recapitalizations, and other corporate events. We recognize share-based compensation expense in the consolidated statement of operations as a component of General and administrative.

Restricted Stock Units

In connection with the closing of IPO, the Company granted 162,500 RSUs to employees under the Plan. These RSUs vest in full after one year of continuous service. In March and April 2025, the Company granted an additional 311,991 RSUs to certain employees and non-employee directors under the Plan. In July 2025, the Company granted an additional 10,086 RSUs to an employee under the Plan. The RSUs granted to employees generally vest ratably over a three-year service period, while the RSUs granted to non-employee directors vest in full on the earlier of (i) the one year anniversary and (ii) the Company's next annual stockholder meeting.

In July and August 2025, the Company accelerated the vesting of 1,779 RSUs awarded to certain former employees based on a pro rata allocation of the service period completed through the date of their respective terminations of employment. This accelerated vesting did not result in any incremental fair value, and therefore, no additional compensation expense was recognized. Upon vesting, the Company issued 1,238 shares of Class A common stock, net of shares withheld to cover employee tax obligations.

The grant-date fair value of each RSU is determined based on the closing stock price of the Company's Class A common stock on the grant date. Share-based compensation expense related to RSUs is recognized on a straight-line basis over the requisite service period, which corresponds to the vesting terms of the respective awards. We account for forfeitures as they occur. The following table summarizes the RSU activity for the year ended December 31, 2025:

	RSUs	Weighted-average grant date fair value
Unvested as of beginning of period	—	
Granted	485,558	$ 18.12
Vested and settled	(1,779)	$ 18.33
Canceled/Forfeited	(50,297)	$ 17.67
Unvested as of end of period	433,482	$ 18.17

The RSUs are entitled to Dividend Equivalent Rights (as defined in the Plan) on unvested RSUs, which are payable only if the underlying RSUs vest. The Company recognized compensation expense for RSUs of $4.7 million for the year ended December 31, 2025.

As of December 31, 2025, unrecognized compensation expense related to unvested RSU awards was $3.2 million, which is expected to be recognized over a weighted-average remaining service period of 1.1 years.

Performance Stock Units

In March 2025, the Company granted 455,601 PSUs under the Plan to certain employees. The PSUs are subject to a performance period from the grant date to December 31, 2027. Vesting is based on the Company's Total Shareholder Return (“TSR”) relative to a defined peer group and the Company's absolute TSR over the performance period. The number of PSUs that may vest ranges from 0% to 300% of the target award, depending on performance outcomes.

The grant-date fair value of the PSUs was estimated using a Monte Carlo simulation model, which reflects the probability of achieving various market-based outcomes and incorporates key assumptions such as expected volatility, risk-free interest rate, expected dividend yield and correlation with the peer group.

	2025
Expected volatility	40.00%
Risk-free rate	4.04%
Expected dividend yield	—%
Correlation with peer group range	45.00% - 68.00%

The fair value was determined on the grant date and will not be remeasured. Compensation expense for the PSUs is recognized on a straight-line basis over the requisite service period, which begins on the grant date and ends on the certification date. Expense is recognized regardless of whether the market conditions are ultimately achieved, provided the service condition is satisfied. The Company accounts for forfeitures as they occur. The PSUs are entitled to Dividend Equivalent Rights (as defined in the Plan) on unvested PSUs, which are payable only if the underlying PSUs vest. The following table summarizes the PSU activity for the year ended December 31, 2025:

	PSUs	Weighted-average grant date fair value
Unvested as of beginning of period	—	
Granted	455,601	$ 22.20
Vested	—	
Canceled/Forfeited	(29,019)	22.20
Unvested as of end of period	426,582	$ 22.20

The Company recognized compensation expense for PSUs of $2.5 million for the year ended December 31, 2025, respectively.

As of December 31, 2025, unrecognized compensation expense related to unvested PSU awards was $6.9 million, which is expected to be recognized over a weighted-average remaining service period of 2.2 years.

Note 14 – Earnings Per Share

Basic earnings (loss) per share is calculated by dividing net (loss) income attributable to Infinity Natural Resources, Inc. by the weighted average number of shares of Class A common stock outstanding during the period. Diluted net (loss) earnings per share gives effect, when applicable, to unvested RSUs and PSUs granted under the Plan and the exchange INR Units (and the cancellation of an equal number of shares of Class B common stock) held by the Legacy Owners into Class A common stock.

The following table summarizes the calculation of weighted average shares of Class A common stock outstanding used in the computation of diluted loss per share:

(in thousands, except per share amounts)	For the Year Ended December 31, 2025	For the Year Ended December 31, 2024
Net income attributable to Infinity Natural Resources, Inc.	$ 13,836	$ —
Net income attributable to redeemable non-controlling interests	$ 40,209	$ —
Diluted net income attributable to Infinity Natural Resources, Inc.	$ 54,045	$ —
Weighted average number of Class A common stock outstanding:		
Basic	15,382,681	—
Effect of dilutive securities:		
INR Units	45,491,091	—
RSUs	80,867	—
PSUs	—	—
Diluted	60,954,639	0
Net income attributable to Infinity Natural Resources, Inc. per share of Class A common stock		
Basic	$ 0.90	$ —
Diluted	$ 0.89	$ —

The calculation of diluted net income per share for the year ended December 31, 2025 excludes (i) the exchange of INR Units (and the cancellation of an equal number of shares of Class B common stock) to Class A common stock and (ii) 433,482 and 426,582 unvested RSUs and PSUs, respectively.

Note 15 – Supplemental Cash Flow Information

The following table provides additional information concerning non-cash activities and cash paid for interest, net of amounts capitalized, for the years ended December 31, 2025, 2024 and 2023:

	For the Year Ended December 31,		
	2025	2024	2023
Supplemental disclosure of non-cash transactions:			
Right-of-use assets and lease liabilities	6	834	18
Net impact of non-cash asset retirement obligations	409	1,917	140
Debt issuance in accrued liabilities	—	645	—
Deferred offering costs included in accounts payable and accrued liabilities	—	5,196	—
Additions to oil and natural gas properties included in accounts payable and accrued liabilities	40,168	50,052	25,453
Additions to other property and equipment included in accounts payable and accrued liabilities	1,858	769	831
Increase in tax receivable agreement liability	$ 1,537	$ —	$ —
Supplemental disclosure of cash flow information			
Interest paid	$ 7,269	$ 19,200	$ 10,136

Note 16 – Commitments and Contingencies

South Bend Utica Farmout Agreement. On March 2, 2018, INR Holdings entered into an Exploration and Development Agreement and Farm Out Agreement (collectively, the "South Bend Utica Development Agreements") with Dominion Energy Transmission, Inc. ("Dominion") covering approximately 11,000 acres in Armstrong and Indiana Counties, Pennsylvania targeting the Utica Shale horizon. This acreage underpins our acreage position at South Bend for Utica development.

The South Bend Utica Development Agreements had an initial term of 15 years and require the drilling of one (1) seven thousand foot lateral into the Utica formation. As of December 31, 2025, we had yet to satisfy that obligation and have approximately 9 years remaining to meet its obligation.

Minimum Future Commitments

The following table summarizes our future commitments related to these oil and natural gas transportation and gathering agreements as of December 31, 2025:

	As of December 31, 2025					
	2026	2027	2028	2029	2030 and thereafter	Total
(in thousands)						
Total minimum future volume commitments	14,093	13,346	13,962	12,677	13,418	67,496
Total minimum future service commitments	5,850	—	—	—	—	5,850
Total minimum future commitments	$ 19,943	13,346	13,962	12,677	13,418	$ 73,346

Lease Commitments. Refer to Note 6 – "Leases" for details on our operating lease agreements. We do not have any finance lease obligations.

Litigation. From time to time, we are party to various legal and/or regulatory proceedings arising in the ordinary course of business. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that all such matters are without merit and involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material effect on our financial condition, results of operations or cash flows.

When it is determined that a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at the time. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, the matter should otherwise be disclosed.

Note 17 – 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.

The following table provides information about the Company's one reportable segment and includes the reconciliation to consolidated net income:

	For the Year Ended December 31,		
	2025	2024	2023
Total revenues	356,431	259,022	161,730
Less:			
Gathering, processing, and transportation	54,779	49,290	31,097
Lease operating	26,675	28,154	18,371
Production and ad valorem taxes	5,918	1,071	886
Depreciation, depletion, and amortization	103,751	73,726	53,796
General and administrative	153,413	13,045	4,885
Other segment (income)/expenses[(1)]	(52,064)	44,450	(33,977)
Segment income	$ 63,959	$ 49,286	$ 86,672

Other segment (income) / expenses are comprised of net interest expense of $9,666, 21,529 and 11,910 for December 31, 2025, 2024 and 2023, respectively, gain/(loss) on derivative instruments of $58,407, (22,047) and 45,322 for December 31, 2025, 2024 and 2023, respectively, other income/(loss) of $(1,535), (874) and 565 for December 31, 2025, 2024 and 2023, respectively, and Income tax expense / (benefit) of $(4,858) and $0 for December 31, 2025, 2024 and 2023.

Note 18 – Subsequent Events

Chase Acquisition. On January 20, 2026, the Company and INR Holdings completed the acquisition of certain non-operated rights, title, and interests in oil and gas properties and related assets located in the South Bend Field in the State of Pennsylvania (the "Chase Acquisition"). The Chase Acquisition was completed pursuant to a purchase and sale agreement entered into with Chase Oil Corporation and certain other sellers.

The consideration for the Chase Acquisition consisted of the issuance of 2,517,194 shares of the Company's Class A common stock.

The Chase Acquisition was completed subsequent to December 31, 2025 and, accordingly, the accompanying consolidated financial statements do not reflect the results of operations, financial position, or cash flows of the acquired interests.

Upstream and Midstream Asset Acquisition. On February 23, 2026, INR Holdings and Northern Oil and Gas, Inc. ("Northern" and, together with INR Holdings, the "Buyers") completed their previously announced acquisitions (collectively, the "Antero Acquisitions") of upstream and midstream assets located in the State of Ohio pursuant to separate purchase and sale agreements dated December 5, 2025, as amended on February 22, 2026.

Pursuant to the amended upstream purchase agreement, INR Holdings and Northern acquired certain rights, title, and interests in upstream oil and gas properties and related assets located in the State of Ohio (the "Upstream Assets") from Antero Resources Corporation, Antero Minerals LLC, and Monroe Pipeline LLC (collectively, the "Upstream Sellers"). INR Holdings acquired an undivided 60% interest in the Upstream Assets, and Northern acquired an undivided 40% interest. The aggregate cash purchase price for the Upstream Assets was approximately $800 million, subject to customary post-closing adjustments.

Pursuant to the amended midstream purchase agreement, INR Holdings and Northern acquired certain gathering, compression, and transportation systems, water facilities and systems, equipment, and related assets located in Belmont, Guernsey, Monroe, Noble, and Washington Counties, Ohio (the "Midstream Assets") from Antero Midstream LLC, Antero Water LLC, and Antero Treatment LLC (collectively, the "Midstream Sellers"). INR Holdings acquired an undivided 60% interest in the Midstream Assets, and Northern acquired an undivided 40% interest. The aggregate cash purchase price for the Midstream Assets was approximately $400 million, subject to customary post-closing adjustments.

The Antero Acquisitions were completed subsequent to December 31, 2025 and, accordingly, the accompanying consolidated financial statements do not reflect the results of operations, financial position, or cash flows of the acquired assets.

Issuance of Preferred Stock. On February 23, 2026, the Company issued and sold an aggregate of 350,000 shares of Series A Convertible Preferred Stock of the Company, par value $0.01 per share (the "Series A Preferred Stock") for gross proceeds of approximately $350 million. After deducting placement agent fees, Infinity received net proceeds of approximately $337.1 million. Of these shares, affiliates of Quantum Capital Group acquired 275,000 shares and affiliates of Carnelian Energy Capital Management, L.P. acquired 75,000 shares (each a "Preferred Purchaser" and, collectively, the "Preferred Purchasers").

The proceeds from the issuance of the Series A Preferred Stock were used to fund a portion of the Antero Acquisitions, with any remaining proceeds to be used for general corporate purposes. The issuance of the Series A Preferred Stock occurred subsequent to December 31, 2025 and, accordingly, the accompanying consolidated financial statements do not reflect the impact of this transaction.

In connection with the issuance of the Series A Preferred Stock, the Company (i) entered into a registration rights agreement with the Preferred Purchasers, pursuant to which the Preferred Purchasers have certain customary registration rights, including rights with respect to the filing of a shelf registration statement, underwritten offering rights and piggyback rights with respect to any shares of Class A common stock of the Company issuable upon conversion of the Series A Preferred Stock, and (ii) amended the INR Holdings LLC Agreement to create a class of convertible preferred units with rights, preferences and privileges that mirror the Series A Preferred Stock. The Company filed a certificate of designation with the Secretary of State of the State of Delaware on February 23, 2026 setting forth the powers, designations, preferences, and other rights of the shares of Series A Preferred Stock.

Amendment to Credit Agreement. On February 23, 2026, INR Holdings entered into a fourth amendment to the Credit Agreement. The fourth amendment, among other things, increased the aggregate elected commitment and borrowing base under the Credit Agreement from $375.0 million to $875.0 million and removed the credit spread adjustment previously applicable to SOFR borrowings. The amendment to the Credit Agreement was completed subsequent to December 31, 2025 and, accordingly, the accompanying consolidated financial statements do not reflect the impact of this amendment.

Note 19 – Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)

Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas exploration and development activities and the related amounts of accumulated depreciation, depletion, and amortization are shown below:

	December 31,		
	2025	2024	2023
(in thousands)			
Proved properties[1]	$ 1,175,523	$ 846,738	$ 615,456
Unproved properties	88,689	86,490	37,189
Total proved and unproved properties	1,264,212	933,228	652,645
Accumulated depreciation, depletion, and amortization	(249,296)	(148,638)	(77,085)
Net capitalized costs	$ 1,014,916	$ 784,590	$ 575,560

(1) Includes asset retirement costs of $3.3 million, $2.7 million and $0.8 million as of December 31, 2025, 2024 and 2023, respectively.

Costs Incurred for Oil and Natural Gas Producing Activities

Our capital costs incurred for acquisition and development activities are shown below:

	December 31,		
	2025	2024	2023
(in thousands)			
Acquisition costs:			
Proved properties	$ 44,585	$ 19,172	$ 274,732
Unproved properties	5,236	89,174	1,047
Development costs	274,723	165,795	144,121
Exploration costs	—	—	—
	$ 324,544	$ 274,141	$ 419,900

Estimated Quantities of Proved Oil and Gas Reserves

The reserve estimates presented below and included herein conform to the definitions prescribed by the SEC. We retained Wright & Company, Inc., an independent petroleum engineering firm, to prepare the estimates of all of its proved reserves as of December 31, 2025, 2024, and 2023 and their related pre-tax future net cash flows. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC.

As of December 31, 2025, all of our oil and gas reserves are attributable to properties within the United States. The table below presents a summary of changes in quantities of proved oil and gas reserves in our estimated proved reserves:

	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBoe)
Total proved reserves:				
December 31, 2022	5,913	358,337	14,152	79,788
Extensions	7,443	168,704	9,015	44,575
Revisions to previous estimates	252	(118,920)	(4,501)	(24,069)
Purchases of reserves in place	18,636	128,110	8,207	48,194
Production	(1,205)	(27,506)	(1,112)	(6,901)
December 31, 2023	31,038	508,725	25,762	141,587
Extensions	9,997	127,429	4,782	36,018
Revisions to previous estimates	(1,301)	9,152	1,335	1,559
Purchases of reserves in place	—	—	—	—
Production	(2,380)	(28,291)	(1,723)	(8,818)
December 31, 2024	37,354	617,015	30,156	170,346
Extensions	3,277	362,633	3,444	67,159
Revisions to previous estimates	(886)	(17,428)	4,157	366
Purchases of reserves in place	—	—	—	—
Production	(3,074)	(45,596)	(2,209)	(12,882)
December 31, 2025	36,671	916,624	35,548	224,989
Proved developed reserves:				
December 31, 2023	13,172	252,832	12,644	67,954
December 31, 2024	14,577	248,634	12,856	68,872
December 31, 2025	14,717	417,362	15,958	100,235
Proved undeveloped reserves:				
December 31, 2023	17,866	255,893	13,118	73,633
December 31, 2024	22,777	368,382	17,300	101,474
December 31, 2025	21,954	499,262	19,589	124,753

Notable changes in proved reserves for the year ended December 31, 2025 included the following:

- *Extensions*. In 2025, total extensions to previous estimates increased proved reserves by 67.2 MMBoe. These extensions primarily related to the addition of 28 PUD locations to be developed by 2030 (as that year entered the 5-year development window) which added 53.0 MMBoe of proved reserves. Other extensions including converting 14.2 MMBoe on 9 wells from proved undeveloped in 2024 to producing in 2025.
- *Revisions to previous estimates*. In 2025, total revisions to previous estimates increased proved reserves by 0.4 MMBoe. These revisions primarily consisted of 4.6 MMBoe of downward revisions from 2024 to 2025 due to 2 PUD locations that were removed due to changes to our development plan. Additionally, our proved developed producing properties had upward revisions of 5.0 MMBoe related to increases in working interest, improvement in expense assumptions, and improvement in type curve.

Notable changes in proved reserves for the year ended December 31, 2024 included the following:

- *Extensions*. In 2024, total extensions to previous estimates increased proved reserves by 36.0 MMBoe. These extensions primarily related to the addition of 27 proved undeveloped ("PUD") locations to be developed by 2029 (as that year entered the 5-year development window) which added 35.3 MMBoe of proved reserves. Other extensions included converting 0.7 MMBoe of unproved reserves to proved developed reserves by drilling eighteen (18) wells during 2024, two of which were producing as of

December 31, 2024. During 2024, our drilling program was focused on adding locations primarily in the various Utica and Point Pleasant formations in Ohio and the Marcellus shale formation in Pennsylvania.

- Revisions to previous estimates. In 2024, total revisions to previous estimates reduced proved reserves by 1.5 MMBoe. These downward revisions primarily consisted of 5.2 MMBoe of revisions to PUD reserves, due to changes to our development plan that resulted in 8 PUD locations being reclassified as they were outside the 5 year development window while the Company performs further technical refinements and analysis to evaluate well spacing assumptions. Additionally, our proved developed producing properties had upward revisions of 6.5 MMBoe and PUD reserves had upward revisions of 0.2 MMBoe related to decreases in capitalized costs which impacted the estimated performance of these wells.

Notable changes in proved reserves for the year ended December 31, 2023 included the following:

- *Extensions*. In 2023, total extensions to previous estimates increased proved reserves by 44.6 MMBoe. These extensions primarily related to the addition of 21 PUD locations to be developed by 2028 (as that year entered the 5-year development window) which added 32.5 MMBoe of proved reserves. Other extensions included converting 12.0 MMBoe of unproved reserves to proved developed reserves by drilling six (6) wells during 2023, two of which were producing as of December 31, 2023. During 2023, our drilling program was focused on adding locations primarily in the various Utica / Point Pleasant formation in Ohio and the Marcellus shale formation in Pennsylvania.
- *Revisions to previous estimates*. In 2023, total revisions to previous estimates reduced proved reserves by 24.1 MMBoe. These downward revisions primarily consisted of 20.8 MMBoe of downward revisions to PUD reserves, due to changes to our development plan that resulted in 18 PUD locations being reclassified as they were outside the 5 year development window while we perform further technical refinements and analysis to evaluate well spacing assumptions. Our proved developed producing properties had upward revisions of 3.3 MMBoe related to increases in commodity prices which impacted the estimated timing and performance of these wells.
- *Purchases of reserves in place*. In 2023, 48.2 MMBoe of proved reserves were added primarily from properties acquired in the Ohio Utica Acquisition on October 4, 2023, including 20.4 MMBoe of proved developed reserves and 27.8 of proved undeveloped locations.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows (the “Standardized Measure”) relating to proved oil and gas reserves has been prepared in accordance with FASB ASC Topic 932, *Extractive Activities – Oil and Gas* (“ASC 932”). Future cash inflows as of December 31, 2025, 2024 and 2023 have been computed by applying average fiscal year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month periods ended December 31, 2025, 2024, 2023, respectively) to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves, based on year-end costs and assuming the continuation of existing economic conditions. The Standardized Measure also includes costs for future dismantlement, abandonment, and rehabilitation obligations.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves.

Future net cash flows are discounted at a rate of 10% annually to derive the Standardized Measure. This calculation does not necessarily result in an estimate of the fair value of our oil and gas properties.

The following table presents our Standardized Measure of discounted future net cash flows:

	December 31,		
(in thousands)	2025	2024	2023
Future cash inflows	$ 5,511,802	$ 4,181,440	$ 3,865,302
Future development costs [1]	(764,219)	(652,135)	(545,803)

Future production costs	(1,824,402)	(1,548,957)	(1,281,802)
Future income tax expense	(531,584)	—	—
Future net cash flows	2,391,597	1,980,348	2,037,697
10% discount to reflect timing of cash flows	(1,310,404)	(1,007,830)	(1,099,313)
Standardized measure of discounted future net cash flows	$ 1,081,193	$ 972,518	$ 938,384

(1) Future development costs include costs associated with the future abandonment of proved properties, including proved undeveloped locations.

The following summarizes the principal sources of change in the Standardized Measure of discounted future net cash flows and such changes have been computed in accordance with ASC 932:

	For the Year Ended December 31,		
	2025	2024	2023
(in thousands)			
Beginning of period	$ 972,518	$ 938,384	$ 1,017,607
Sales of oil, natural gas, NGLs, net of production costs	(263,003)	(176,822)	(109,179)
Acquisitions of reserves	—	—	534,927
Extensions, net of future development costs	299,655	200,954	199,378
Net change in price and production costs	238,597	(264,003)	(643,905)
Previously estimated development costs incurred	118,750	140,274	68,412
Change in estimated future development costs	(27,274)	(7,170)	4,734
Revisions of previous quantity estimates	22,064	45,803	(224,318)
Accretion of discount	79,321	93,838	101,761
Net change in income taxes	(251,800)	—	—
Net change in timing of production and other	(107,635)	1,260	(11,034)
End of period	$ 1,081,193	$ 972,518	$ 938,384

Future net revenues included in the Standardized Measure relating to proved oil and natural gas reserves incorporate weighted average sales prices (inclusive of adjustments for transportation, quality, and basis differentials) for each of the periods indicated below as follows:

	December 31,		
	2025	2024	2023
Oil (per Bbl)	$ 58.61	$ 67.98	$ 73.73
Natural gas (per MMBtu)	$ 2.77	$ 1.42	$ 1.74
NGL (per Bbl)	$ 23.20	$ 25.48	$ 26.87

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

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated, as of December 31, 2025, the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Our disclosure control and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2025, our disclosure controls and procedures were not effective because of certain material weaknesses in our internal control over financial reporting, as further described below.

Management's Annual Report on Internal Control Over Financial Reporting

Management, including the Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect all 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 policies or procedures may deteriorate

Under the supervision of, and with the participation of, our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control—Integrated Framework in 2013, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management determined that we did not maintain effective internal control over financial reporting as of December 31, 2025 as a result of the material weaknesses described below.

Previously Disclosed Material Weaknesses

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that a reasonable possibility exists that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis.

Our management concluded that the following material weaknesses in internal control over financial reporting, previously disclosed in Item 9A of the Company's Annual Report on Form 10-K for the year ended December 31, 2024, were not fully remediated as of December 31, 2025. These material weaknesses relate to:

- Segregation of duties – We did not design and implement processes which allowed for appropriate segregation of duties, including our process of reviewing and approving journal entries.

- Risk assessment – We did not design and implement an effective risk assessment based on the criteria established in the COSO framework.

- Control activities – We did not design and implement effective control activities based on the criteria established in the COSO framework, including those over information technology.

- Formal accounting policies and procedures – We have not formalized a comprehensive accounting policies and procedures memo in accordance with US GAAP.

- Accounting and financial reporting resources – We did not maintain a sufficient complement of accounting and financial reporting resources commensurate with our financial reporting requirements.

This Annual Report does not include an attestation report of our independent registered accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies. Our independent registered accounting firm will not be required to opine on the effectiveness of our internal control over financial reporting pursuant to Section 404 until we are no longer an "emerging growth company" as defined in the JOBS Act.

Remediation Efforts to Address the Previously Disclosed Material Weaknesses

With oversight from the Audit Committee of the Company's board of directors and input from the Company's board of directors, management is in the process of designing and implementing changes in processes and controls to remediate the material weaknesses described above. The measures we are taking to remediate the identified material weaknesses and further evolve our accounting processes include:

- Continued expansion of the accounting and financial reporting team with experienced personnel to strengthen segregation of duties and review processes.

- Continued development of comprehensive accounting policies and procedures aligned with U.S. GAAP, with finalization, formal adoption, and sustained execution subject to continued remediation efforts.

- Designed and implemented control activities that contemplate segregation of duties.

- Designed and implemented a formal risk assessment framework consistent with COSO standards, with continued execution and monitoring required to demonstrate sustained operating effectiveness.

- Strengthening IT governance and designing IT general controls, including program change management, restricting user access to our internal systems used for financial reporting and enhancing the retention of contemporaneous documentation of reviews over IT general controls.

While we have made significant progress towards the remediation of the material weaknesses noted above, management has concluded that the material weaknesses were not fully remediated as of December 31, 2025. The material weaknesses will not be considered remediated until the applicable controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

Changes in Internal Control Over Financial Reporting

Except for changes relating to remediation efforts described above, there were no changes during the quarter ended December 31, 2025 in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Disclosure in lieu of reporting on a Current Report on Form 8-K.

None.

Rule 10b5-1 Trading Arrangements

From time to time, our officers (as defined in Rule 16a–1(f)) and directors may enter into Rule 10b5-1 or non-Rule 10b5-1 trading arrangements (as each such term is defined in Item 408 of Regulation S-K). During the three months ended December 31, 2025, none of our officers or directors adopted or terminated any such trading arrangements.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors and Executive Officers

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Deloitte & Touche LLP (PCAOB ID No. 34) has served as our independent registered public accounting firm since 2023.

The information required in response to this item will be set forth in our definitive proxy statement for the 2026 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial statements and financial statement schedules filed as part of this Annual Report are listed in the index included in “Item 8. Financial Statements and Supplementary Data” of Part II of this Annual Report. All valuation and qualifying accounts schedules have been omitted because they are either not material, not required, not applicable or the information required to be presented is included in our combined and consolidated financial statements and related notes.

(a)(3) See Exhibits list below.

(b) See Exhibits list below.

(c) None.

		Incorporated by Reference		
Exhibit Number	**Description**	**Form**	**Exhibit Number**	**Filing Date**
2.1†	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.	8-K	2.1	December 8, 2025

2.2†	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.	8-K	2.2	December 8, 2025
2.3†	Amendment No. 1 to the Purchase and Sale Agreement, dated as of February 22, 2026, 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.	8-K	2.3	February 23, 2026
2.4†	Amendment No. 1 to the Purchase and Sale Agreement, dated as of February 22, 2026, 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.	8-K	2.4	February 23, 2026
3.1	Amended and Restated Certificate of Incorporation of Infinity Natural Resources, Inc.	8-K	3.1	February 3, 2025
3.2	Amended and Restated Bylaws of Infinity Natural Resources, Inc.	8-K	3.2	February 3, 2025
3.3	Certificate of Designation of Series A Convertible Preferred Stock of Infinity Natural Resources, Inc., as filed with the Secretary of State of the State of Delaware on February 23, 2026.	8-K	3.1	February 23, 2026
4.1	Registration Rights Agreement, dated February 3, 2025, by and among the Company and each of the other signatories from time to time party thereto.	8-K	4.1	February 3, 2025
4.2	Registration Rights Agreement, dated February 23, 2026, by and among the Company and each of the other signatories from time to time party thereto.	8-K	4.1	February 23, 2026
4.3*	Description of Capital Stock.			
10.1†++	Second Amended and Restated Limited Liability Company Agreement of Infinity Natural Resources, LLC, dated as of January 30, 2025, by and among the Company and the other signatories parties thereto.	8-K	10.1	February 3, 2025
10.2	Amendment No. 1 to the Second Amended and Restated Limited Liability Company Agreement of Infinity Natural Resources, LLC, dated as of February 23, 2026.	8-K	10.2	February 23, 2026
10.3	Tax Receivable Agreement, dated as of January 30, 2025, by and among the Company and the TRA Parties (as defined in the Tax Receivable Agreement).	8-K	10.2	February 3, 2025
10.4†	Credit Agreement, dated as of September 25, 2024, by and among, Infinity Natural Resources, LLC, the lenders from time to time party thereto and Citibank, N.A., as the administrative agent and an issuing bank.	S-1	10.1	October 4, 2024
10.5	First Amendment to Credit Agreement, dated as of March 31, 2025, by and among, Infinity Natural Resources, LLC, the lenders party thereto and Citibank, N.A., as the administrative agent, collateral agent and an issuing bank.	8-K	10.1	April 1, 2025

10.6	Second Amendment to Credit Agreement, dated as of May 29, 2025, by and among, Infinity Natural Resources, LLC, the lenders party thereto and Citibank, N.A., as the administrative agent, collateral agent and an issuing bank.	8-K	10.1	May 29, 2025
10.7	Third Amendment to Credit Agreement, dated as of December 5, 2025, by and among, Infinity Natural Resources, LLC, the lenders party thereto and Citibank, N.A., as the administrative agent, collateral agent and an issuing bank.	8-K	10.1	December 8, 2025
10.8	Fourth Amendment to Credit Agreement, dated as of February 23, 2026, by and among, Infinity Natural Resources, LLC, the lenders party thereto and Citibank, N.A., as the administrative agent, collateral agent and an issuing bank.	8-K	10.3	February 23, 2026
10.9	Form of Indemnification Agreement.	S-1	10.2	October 4, 2024
10.10	Securities Purchase Agreement, by and among Infinity Natural Resources, Inc., INR (II) Investments, LLC and Etineles Holdings V, LLC, dated as of February 18, 2026.	8-K	10.1	February 23, 2026
10.11††	Infinity Natural Resources, Inc. Omnibus Incentive Plan.	8-K	10.3	February 3, 2025
10.12††	Infinity Natural Resources, Inc. Executive Change in Control and Severance Plan.	8-K	10.4	February 3, 2025
10.13††	Form of Participation Agreement pursuant to Infinity Natural Resources, Inc. Executive Change in Control and Severance Plan.	8-K	10.5	February 3, 2025
10.14††	Form of RSU Grant Notice and Award Agreement (Non-Employee Director) pursuant to Infinity Natural Resources, Inc. Omnibus Incentive Plan.	S-8	99.1	February 3, 2025
10.15††	Form of RSU Grant Notice and Award Agreement (Employee) pursuant to Infinity Natural Resources, Inc. Omnibus Incentive Plan.	S-8	99.2	February 3, 2025
19.1++	Infinity Natural Resources, Inc. Insider Trading Policy.	10-K	19.1	March 28, 2025
21.1*	List of Subsidiaries of Infinity Natural Resources, Inc.			
23.1*	Consent of Deloitte & Touche LLP (Infinity Natural Resources, Inc.).			
23.2*	Consent of Wright & Company, Inc.			
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.			
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.			
32.1+	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.			
32.2+	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.			
97.1	Clawback Policy of Infinity Natural Resources, Inc.	10-K	97.1	March 28, 2025
99.1*	Wright & Company, Inc. Summary of Reserves at December 31, 2025.			

99.2	Wright & Company, Inc. Summary of Reserves at December 31, 2024.	10-K	97.1	March 28, 2025
99.3	Wright & Company, Inc. Summary of Reserves at December 31, 2023.	S-1	99.1	October 4, 2024

* Filed herewith.
\+ Furnished herewith.
++ Certain portions of this document that constitute confidential information have been redacted in accordance with Regulation S-K, Item 601(b)(10). The Company hereby agrees to furnish a copy of any omitted portion to the SEC upon request.
†† Certain personally identifiable information has been omitted from this exhibit pursuant to Item 601(a)(6) under Regulation S-K.
† Certain of the schedules and exhibits to the agreement have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule or exhibit will be furnished to the SEC upon request.
** Management contract of compensatory plan or agreement.

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, as amended, the Registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

INFINITY NATURAL RESOURCES, INC.

Date: March 10, 2026

By: /s/ Zack Arnold
Zack Arnold
President, Chief Executive Officer and Director

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

Name	Title	Date
/s/ Zack Arnold **Zack Arnold**	President, Chief Executive Officer and Director (Principal Executive Officer)	March 10, 2026
/s/ David Sproule **David Sproule**	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	March 10, 2026
/s/ Brian Pietrandrea **Brian Pietrandrea**	Chief Accounting Officer (Principal Accounting Officer)	March 10, 2026
/s/ Steven Gray **Steven Gray**	Chairman	March 10, 2026
/s/ Steven Cobb **Steven Cobb**	Director	March 10, 2026
/s/ Katherine M. Gallagher **Katherine M. Gallagher**	Director	March 10, 2026
/s/ Scott Gieselman **Scott Gieselman**	Director	March 10, 2026
/s/ Matthew Kelly **Matthew Kelly**	Director	March 10, 2026
/s/ David Poole **David Poole**	Director	March 10, 2026
/s/ William J. Quinn **William J. Quinn**	Director	March 10, 2026

Board of Directors

Zack Arnold

Steven Cobb

Katherine Gallagher

Scott Gieselman

Steven Gray

Matthew Kelly

Scott McNeill

David Poole

William Quinn

David Sproule

Executive Officers

Zack Arnold
President and Chief Executive Officer

David Sproule
Executive Vice President and Chief Financial Officer

Raleigh Wolfe
General Counsel and Secretary

Company Information

Corporate Headquarters
2605 Cranberry Square
Morgantown, WV 26508
304-212-2350
info@infinitynr.com
www.infinitynatuaralresources.com

Independent Registered Public Accounting Firm
Deloitte & Touche LLP

Registrar and Stock Transfer Agent
Equiniti Trust Company, LLC

Stock Exchange
Our Class A common stock is traded on the New York Stock Exchange under the symbol INR

Investor Relations
Thomas Marchetti
ir@infinitynr.com