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

FORM 10-K

(Mark One)

x **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

o **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 001-41849

Mach Natural Resources LP

(Exact name of registrant as specified in its charter)

Delaware	**93-1757616**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
14201 Wireless Way, Suite 300, Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	(Zip Code)

(405) 252-8100
Registrant's telephone number, including area code

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common units representing limited partner interests	MNR	New York Stock Exchange

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

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

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files).Yes x No o

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

Large accelerated filer	o	Accelerated filer	x
Non-accelerated filer	o	Smaller reporting company	o
		Emerging growth company	x

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. x

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. o

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. o

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). o

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2025, based on the closing price of $14.44 for common units of the registrant as reported by the New York Stock Exchange, was approximately $423.8 million.

The registrant had 168,218,770 common units outstanding as of March 5, 2026.

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GLOSSARY OF OIL AND GAS TERMS AND OTHER TERMS

The terms and abbreviations defined in this section are used throughout this Annual Report on Form 10-K (this "Annual Report"):

"**Adjusted EBITDA**." Net income before (1) interest expense, net, (2) depreciation, depletion, amortization and accretion, (3) unrealized (gain) loss on derivative instruments, (4) impairment of oil and gas properties, (5) loss on debt extinguishment (6) equity-based compensation expense and (7) gain on sale of assets, net.

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

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

"**Bbtu**." One billion Btu.

"**BCE**" or "**Sponsor**." Investment funds managed by Bayou City Energy Management LLC and affiliates thereof.

"**BCE-Mach**." BCE-Mach LLC, a Delaware limited liability company.

"**BCE-Mach II**." BCE-Mach II LLC, a Delaware limited liability company.

"**BCE-Mach III**" or "**Predecessor**." BCE-Mach III LLC, a Delaware limited liability company.

"**BCE-Mach Aggregator**." BCE-Mach Aggregator LLC, a Delaware limited liability company.

"**BCE-Stack**." BCE-Stack Development LLC, a Delaware limited liability company.

"**Boe**." One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to one Bbl of oil.

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

"**Code**." Internal Revenue Code of 1986, as amended.

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

"**Developed acreage**." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"**Developed reserves**." Developed reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

"**Existing Owners**." Collectively refers to BCE and the Management Members.

"**Exploratory well**." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined under Regulation S-X.

"**Extension well**." A well drilled to extend the limits of a known reservoir.

"**Field**." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

“**First Amendment”** Refers to the First Amendment to the New Credit Agreement, Dated as of September 12, 2025, among the Company, the lenders and issuing banks party thereto and Truist Bank, as administrative agent and collateral agent.

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

“**Fracturing**” or “**fracture stimulation techniques**.” The technique of improving a well’s production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

“**General partner agreement**.” The Amended and Restated Limited Liability Company Agreement of Mach Natural Resources GP LLC.

“**Gross wells**.” The total wells in which a working interest is owned.

“**Holdco**.” Mach Natural Resources Holdco LLC, a Delaware limited liability company.

“**Horizontal drilling**.” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

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

“**Intermediate**.” Mach Natural Resources Intermediate LLC, a Delaware limited liability company.

“**Lease operating expense**.” The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

“**LNG**.” Liquified natural gas.

“**Management Members**.” Collectively refers to our current officers and employees who own indirect equity interests in the Mach Companies, including equity interests held by certain trusts affiliated with Mr. Ward.

“**Mach Companies**.” Collectively refers to BCE-Mach, BCE-Mach II, and BCE-Mach III.

“**Mach Resources**.” Mach Resources LLC.

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

“**MBoe**.” One thousand Boe.

“**MBoe/d**.” One thousand Boe per day.

“**Mcf**.” One thousand cubic feet of natural gas.

“**MMBtu**.” One million Btu.

“**MMcf**.” One million cubic feet of natural gas.

“**MMcf/d**.” One million cubic feet of natural gas per day.

“**NGLs**.” Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

“**New Credit Agreement**.” Refers to the senior secured revolving credit agreement, dated as of February 27, 2025, among the Company, the lenders party thereto, and Truist Bank as administrative agent.

“**Net wells**.” The percentage of gross wells an owner has. An owner who has 50% interest in 100 gross wells owns 50 net wells.

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

"**NYSE**." The New York Stock Exchange.

"**OGT**." ONEOK Gas Transmission.

"**OPEC +**." Organization of the Petroleum Exporting Countries.

"**Partnership agreement**." The Amended and Restated Agreement of Limited Partnership of Mach Natural Resources LP.

"**PCAOB**." The Public Company Accounting Oversight Board.

"**PDP**." Proved developed producing.

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

"**Proved reserves**." Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For a complete definition of proved crude oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

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

"**PV-10**." When used with respect to oil and natural gas reserves, PV-10 represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our Standardized Measure, the most comparable measure under GAAP. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"**Recompletion**." The process of re-entering an existing wellbore that is either producing or not producing and completing reservoirs in an attempt to establish or increase existing production.

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

"**Revolving Credit Agreement**." Refers to the senior secured revolving credit agreement, dated as of December 28, 2023, among the Company, the lenders party thereto, and MidFirst Bank as administrative agent.

"**SEC Pricing**." The oil and gas price parameters established by the current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"**Standardized Measure**." Standardized Measure is our standardized measure of discounted future net cash flows, which is prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation. However, our operations are subject to the Texas franchise tax.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. The standardized measure does not represent management’s estimate of our future cash flows or the value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as effected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

“**Term Loan Credit Agreement**.” Refers to the senior secured term loan credit agreement, dated as of December 28, 2023, among the Company, the lenders party thereto, Texas Capital Bank, as agent, and Chambers Energy Management, LP, as the arranger.

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

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

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

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

“**WTI**.” West Texas Intermediate.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Annual Report contains or incorporates by reference information that includes or is based upon “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Exchange Act of 1934, as amended (the “Exchange Act”). 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 under “Risk Factors” in this Annual Report.

Forward looking statements may include statements about:

- our business strategy;
- our estimated proved reserves;
- our ability to distribute cash available for distribution and achieve or maintain certain financial and operational metrics;
- our drilling prospects, inventories, projects and programs;
- general economic conditions;
- actions taken by OPEC + as it pertains to the global supply and demand of, and prices for, oil, natural gas and NGLs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, leverage, liquidity and capital required for our development program;
- our pending legal or environmental matters;
- our realized oil and natural gas prices;
- the timing and amount of our future production of natural gas;
- our hedging strategy and results;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our marketing of natural gas;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- credit markets;
- our decline rates of our oil and natural gas properties;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development and production of oil, natural gas and NGLs. We disclose important factors that could cause our actual results to differ materially from our expectations as described under “Risk Factors” included in Item 1A of Part I of this Annual Report. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statement include:

- commodity price volatility;

- the impact of epidemics, outbreaks or other public health events, and the related effects on financial markets, worldwide economic activity and our operations;
- uncertainties about our estimated oil, natural gas and NGL reserves, including the impact of commodity price declines on the economic producibility of such reserves, and in projecting future rates of production;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- lack of transportation and storage capacity as a result of oversupply, government regulations or other factors;
- lack of availability of drilling and production equipment and services;
- potential financial losses or earnings reductions resulting from our commodity price risk management program or any inability to manage our commodity risks;
- failure to realize expected value creation from property acquisitions and trades;
- access to capital and the timing of development expenditures;
- environmental, weather, drilling and other operating risks;
- regulatory changes, including potential shut-ins or production curtailments mandated by the Railroad Commission of Texas, the Oklahoma Corporation Commission and/or the Kansas Corporation Commission;
- competition in the oil and natural gas industry;
- loss of production and leasehold rights due to mechanical failure or depletion of wells and our inability to re-establish their production;
- our ability to service our indebtedness;
- any downgrades in our credit ratings that could negatively impact our cost of and ability to access capital;
- cost inflation;
- the potential for significant new tariffs and their impact on global oil, natural gas and NGL markets;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; and
- risks related to our ability to expand our business, including through the recruitment and retention of qualified personnel.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir 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 further production and development drilling. Accordingly, our reserve and PV-10 estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties materialize, or should underlying assumptions prove to be 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.

RISK FACTOR SUMMARY

The following is a summary of the principal risks that could adversely affect our business, operations and financial results. Please refer to “Risk Factors” included in Item 1A of Part I of this Annual Report below for additional discussion of the risks summarized in this Risk Factor Summary.

Risks Related to Cash Distributions

- We may not have sufficient available cash to pay any quarterly distribution on our common units following the payment of expenses, funding of development costs and establishment of cash reserves.
- The amount of our quarterly cash distributions from our available cash, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Risks Related to Our Business

- Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.
- 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 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.
- The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.
- The marketability of our production is dependent upon gathering, treating, processing and transportation facilities, some of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues could decrease.
- 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.
- We depend on Mach Resources to provide us services necessary to operate our business. If Mach Resources were unable or unwilling to provide these services, it would result in a disruption in our business that could have an adverse effect on our financial position, financial results and cash flow.
- The unavailability or high cost of drilling rigs, frac 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.
- Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.
- Events outside of our control, including widespread public health crises, epidemics and outbreaks of infectious diseases, or the threat thereof, and any related threats of recession and other economic repercussions could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.
- Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and reduction in demand for oil and natural gas.
- Increased scrutiny of environmental, social, and governance (“ESG”) matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

Risks Inherent in an Investment in Us

- Our general partner and its affiliates own a controlling interest in us and have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

- Our partnership agreement does not restrict the Sponsor (as defined below) from competing with us. Certain of our directors and officers may in the future spend significant time serving, and may have significant duties with, investment partnerships or other private entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.
- Our partnership agreement replaces our general partner’s fiduciary duties to us and our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.
- Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, which could reduce the price at which our common units will trade.
- Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.
- Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.
- Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent.
- We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for U.S. federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.
- Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.
- The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

Part I

Items 1 and 2. Business and Properties

Business Overview

Mach Natural Resources LP (either individually or together with its consolidated subsidiaries, as the context requires, the “Company” or “Mach”) is an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas; the San Juan Basin region of New Mexico and Colorado; and the Permian Basin region of West Texas.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Woodford and Mississippian, Mancos and Fruitland formations. Our experience across these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments. We also own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. Our midstream assets enhance the value of our properties by allowing us to optimize pricing, increase flow assurance and eliminate third-party costs and inefficiencies. In addition, our owned midstream systems generate third-party revenue.

Corporate Reorganization

On October 25, 2023, the Company underwent a corporate reorganization (the “Corporate Reorganization”) whereby (a) the owners who directly held membership interests in the Mach Companies prior to the Offering (as defined below) (the “Existing Owners”) contributed 100% of their membership interests in each of the Mach Companies for a pro rata allocation of 100% of the limited partner interests in the Company with BCE-Mach III determined as the accounting acquirer of the net assets and operations of BCE-Mach and BCE-Mach II through a business combination, (b) the Company contributed 100% of its membership interests in the Mach Companies to Intermediate in exchange for 100% of the membership interests in Intermediate, and (c) Intermediate contributed 100% of its membership interests in the Mach Companies to Holdco in exchange for 100% of the membership interests in Holdco.

Our financial and operating data for the year ended December 31, 2023 includes BCE-Mach III for the entire period and BCE-Mach LLC and BCE-Mach II LLC from October 25, 2023, the effective date of the acquisition as a result of the Corporate Reorganization.

Initial Public Offering

On October 27, 2023, the Company completed the offering of 10,000,000 common units at a price of $19.00 per unit to the public (the “Offering”). The sale of Company’s common units resulted in gross proceeds of $190.0 million to the Company and net proceeds of $168.5 million, after deducting underwriting fees and offering expenses. The material terms of the Offering are described in the Company’s final prospectus, filed with the U.S. Securities and Exchange Commission (“SEC”) on October 26, 2023, pursuant to Rule 424(b)(4) of the Securities Act.

The Company used $102.2 million of the proceeds to pay down the existing credit facilities of its operating subsidiaries and $66.3 million of the proceeds to purchase 3,750,000 common units from the existing common unit owners on a pro rata basis. After giving effect to the Offering and the transactions related thereto, the Company had 95,000,000 common units issued and outstanding.

Information About Us

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

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

Properties

Our assets are located throughout Western Oklahoma, Southern Kansas, the panhandle of Texas, West Texas, Northwest New Mexico, Southwest Colorado and Southwest Wyoming and consist of approximately 12,000 gross operated PDP wells. Our average net daily production for the year ended December 31, 2025 was approximately 103 MBoe/d. Our wells are primarily located across three basins: the Anadarko Basin, the San Juan Basin and the Permian Basin.

Additionally, we own a portfolio of midstream assets which support our leases, including ownership in six processing plants with combined processing capacity of 1,303 MMcf/d, along with 2,905 miles of gas gathering pipelines. Additionally, we own water infrastructure consisting of 1,120 miles of gathering pipeline and 177 disposal wells.

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. Funding sources for our acquisitions have included proceeds from borrowings under our revolving credit facilities, contributions from our equity partners and cash flow from operating activities. We spent approximately $251.9 million in 2025 on development costs and our budget for 2026 is between $315.0 million and $360.0 million. For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2026 is anticipated to focus on a mix of drilling Mississippian and Mancos wells.

During the year ended December 31, 2025, we spent approximately $205.1 million on drilling and completion activities and related equipment and spud 27.1 net wells while bringing online 34.1 wells, $38.5 million on remedial workovers and other capital projects, $8.3 million on midstream and other property and equipment capital projects and $1.3 billion on acquisitions.

Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2026 capital development programs from cash flow from operations.

Our 2026 capital expenditures program is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, including acid to be used for our acid stimulation completion, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows and reduce our cash available for distribution to unitholders.

Oil and Natural Gas Reserves

Reserve Data

The information with respect to our estimated proved reserves based on SEC pricing presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following tables provide a summary of our estimated proved reserves and related PV-10 of proved reserves as of using SEC pricing, based on evaluations prepared by our independent reserve engineers: Netherland, Sewell & Associates, Inc, and Cawley, Gillespie & Associates Inc. for the year ended December 31, 2025, and Cawley, Gillespie & Associates Inc. for the year ended December 31, 2024. See "— Preparation of reserve estimates" for the definitions of proved reserves and the technologies and economic data used in their estimation. Prices were adjusted for quality, energy content, transportation fees and market differentials, as applicable. The risk factors contained in this Annual Report including "Risk Factors — Risks Related to Our Business — Oil and natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, cash available for distribution and results of operations, liquidity and our ability to meet our financial commitments or cause us to delay our planned capital expenditures" and "Risk Factors — Risks Related to Our Business — 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," included in Item 1A of Part I of this Annual Report contain more information regarding the uncertainty associated with price and reserve estimates.

Summary Reserve Data

Our historical SEC reserves, PV-10 and Standardized Measure of proved reserves were calculated using oil and gas price parameters established by current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions ("SEC Pricing"). These prices were adjusted for differentials on a per-property basis, which may include local basis differential, fuel costs and shrinkage. All prices are held constant throughout the lives of the properties.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Item 7 of Part II of this Annual Report and "— Oil, Natural Gas and NGL Production Prices and Production Costs" in evaluating the material presented below.

	As of December 31,	
Reserve Data based on SEC Pricing[1]	**2025**	**2024**
Proved Developed:		
Oil (MBbl)	90,869	46,056
Natural gas (MMcf)	2,176,382	808,820
Natural gas liquids (MBbl)	90,793	66,772
Total equivalent (MBoe)	544,392	247,630
PV-10 (in millions)[2]	$ 2,877	$ 1,635
Proved Undeveloped:		
Oil (MBbl)	13,329	21,379
Natural gas (MMcf)	733,369	263,182
Natural gas liquids (MBbl)	24,782	24,378
Total equivalent (MBoe)	160,340	89,620
PV-10 (in millions)[2]	$ 211	$ 255
Total Proved:		
Oil (MBbl)	104,198	67,435
Natural gas (MMcf)	2,909,751	1,072,002
Natural gas liquids (MBbl)	115,575	91,150
Total equivalent (MBoe)	704,732	337,250
PV-10 (in millions)[2]	$ 3,088	$ 1,890
Standardized Measure (in millions)[2]	$ 3,080	$ 1,890

(1) Our estimated net proved 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 barrel for oil and $3.39 per MMbtu for natural gas at December 31, 2025 and $75.48 per barrel 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, which may include local basis differentials, fuel costs and shrinkage.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. For more information on how we calculate PV-10 and a reconciliation of proved reserves PV-10 to its nearest GAAP measure, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure" included in Item 7 of Part II of this Annual Report.

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2025 and 2024 included in this Annual Report are based on evaluations prepared by the independent petroleum engineering firm of Cawley, Gillespie & Associates Inc. and Netherland, Sewell & Associates, Inc. in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves

Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering similar resources.

Under SEC rules, 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 expire, 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. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs and available downhole and production data and well-test data.

Reserve engineering is, and must be recognized as, a subjective process of estimating volumes of economically recoverable 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 natural gas that are ultimately recovered. Estimates of economically recoverable natural gas and of future net cash flows are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See "Risk Factors" included in Item 1A of Part I of this Annual Report.

Internal Controls Over Reserve Estimates

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their preparation of reserve estimates. 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, natural gas and NGLs that are ultimately recovered. See "Risk Factors — Risks Related to Our Business — 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" included in Item 1A of Part I of this Annual Report for more information. The reserves engineering group is responsible for the internal review of reserve estimates, and the technical person primarily responsible for overseeing the preparation of our reserve estimates has more than nine years of experience in reserve engineering and has been with the Company since 2019. The reserves engineering group is independent of any of our operating areas. The reserves engineering group reviews the estimates with our third-party petroleum consultants, Cawley, Gillespie & Associates, and Netherland, Sewell & Associates, our independent petroleum engineering firms.

Cawley, Gillespie & Associates is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. The lead evaluator that prepared the reserve report was J. Zane Meekins, P.E., Executive Vice President at Cawley, Gillespie & Associates.

Mr. Meekins has been with Cawley, Gillespie & Associates since 1989 and graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins is a State of Texas registered professional engineer (License #71055) and a member of the Society of Petroleum Evaluation Engineers and the Society of Petroleum Engineers. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Mr. Meekins is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves reports are Joseph Mello and Matthew D. Pankey.

Mr. Mello has been practicing consulting petroleum engineering at NSAI since 2015. Mr. Mello is a Licensed Professional Engineer in the State of Texas (No. 125699) and has over 5 years of prior industry experience. He graduated from Rice

University in 2010 with a Bachelor of Science Degree in Chemical Engineering. The technical principal meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; the technical principal is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. Mr. Pankey, a Licensed Professional Engineer in the State of Texas (No. 142931), has been practicing consulting petroleum engineering at NSAI since 2019 and has over 6 years of prior industry experience. He graduated from Auburn University in 2012 with a Bachelor of Science Degree in Chemical Engineering. The technical principal meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2025, our proved undeveloped reserves were composed of 13,329 MBbls of oil, 733,369 MMcf of natural gas and 24,782 MBbls of NGLs for a total of 160,340 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs, for the year ended December 31, 2025 (in MBoe):

Balance, December 31, 2024	89,620
Purchases of reserves	82,734
Revisions of previous estimates	1,718
Transfers to proved developed	(13,732)
Balance, December 31, 2025	160,340

Revisions of previous estimates of 1,718 MBoe during the year ended December 31, 2025 included the addition of 18 PUDs (21,081 MBoe) based on increasing our drilling activity within proven areas of development, the removal of 87 PUDs (19,075 MBoe) due to changing corporate priorities, and higher commodity prices (1,948 Mboe). Additionally, changes to reflect current market conditions on lease operating expenses and product price differentials totaled 2,237 MBoe.

We converted 13,732 MBoe of PUDs into proved developed reserves in 2025. Costs incurred relating to the development of all oil and natural gas reserves were $205.1 million during the year ended December 31, 2025.

We drilled 29 gross wells during 2025. We expect to drill or participate in the drilling of approximately 43 gross wells during 2026.

All of our PUD drilling locations are scheduled to be drilled within five years of December 31, 2025. We anticipate drilling and completing or participating in the drilling and completion of approximately 43 PUD locations during 2026, 76 during 2027, 79 during 2028, 50 during 2029 and 11 during 2030. These PUD locations relate to 160,340 MBoe of PUD reserves. Our development costs relating to the development of our PUDs at December 31, 2025 are projected to be approximately $227.6 million in 2026, $297.0 million in 2027, $317.1 million in 2028, $207.8 million in 2029 and $35.1 million in 2030 for a total of $1,084.6 million of future development costs. All of these PUD drilling locations are part of a development plan and a budget that is reviewed annually and adopted by management. We expect that the substantial cash flow generated by our existing wells, in addition to availability under the New Credit Agreement, will be sufficient to fund our drilling program, maintenance capital expenditures and PUD conversion into proved developed reserves in accordance with our development schedule. Please see “Risk Factors — Risks Related to Our Business — 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.” included in Item 1A of Part I of this Annual Report.

Oil, Natural Gas and NGL Production Prices and Production Costs

Production and Price History

Our production is primarily concentrated across three basins: the Anadarko Basin, the San Juan Basin and the Permian Basin. The following table sets forth information regarding our net production volumes and average realized prices for the periods indicated.

	Year Ended December 31,		
	2025	2024	2023
Net Production Volumes:			
Oil (MBbl)	7,719	7,382	5,445
Natural gas (MMcf)	135,026	101,147	59,378
NGLs (MBbl)	7,507	7,489	3,068
Total (MBoe)	37,731	31,729	18,409
Average daily production (MBoe/d)	103.37	86.69	50.44
Average Realized Prices (excluding effects of realized derivatives):			
Oil (MBbl)	$ 63.72	$ 75.27	$ 77.57
Natural gas (MMcf)	$ 2.76	$ 1.93	$ 2.52
NGLs (MBbl)	$ 23.00	$ 24.79	$ 24.52
Average Realized Prices (including effects of realized derivatives):			
Oil (MBbl)	$ 66.02	$ 74.55	$ 76.51
Natural gas (MMcf)	$ 3.00	$ 2.15	$ 2.76
NGLs (MBbl)	$ 23.00	$ 24.79	$ 24.52

Operating Data

The following table sets forth information regarding our revenues and operating expenses for the years ended December 31, 2025, 2024 and 2023:

	Year Ended December 31,		
($ in thousands)	2025	2024	2023
Revenues:			
Oil	$ 491,837	$ 555,692	$ 422,312
Natural gas	373,134	195,472	149,795
Natural gas liquids	172,679	185,621	75,245
Total oil, natural gas, and NGL sales	1,037,650	936,785	647,352
Gain (loss) on oil and natural gas derivatives, net	81,289	(18,854)	57,272
Midstream revenue	27,561	24,341	26,328
Product sales	28,890	27,356	31,357
Total revenues	$ 1,175,390	$ 969,628	$ 762,309
Operating Costs and Expenses:			
Gathering and processing expense	$ 138,836	$ 106,152	$ 39,449
Lease operating expense	263,793	180,513	127,602
Production taxes	48,761	45,674	31,882
Midstream operating expense	13,319	10,466	10,873
Cost of product sales	25,901	24,026	28,089
Depreciation, depletion, amortization and accretion expense – oil and natural gas	280,459	261,949	131,145
Depreciation and amortization expense – other	12,305	9,018	6,472
General and administrative	56,636	40,838	27,653
Impairment of oil and gas properties	90,430	—	—
Total operating expenses	$ 930,440	$ 678,636	$ 403,165
Operating Costs and Expenses (per Boe):			
Gathering and processing expense	$ 3.68	$ 3.35	$ 2.14
Lease operating expense	$ 6.99	$ 5.69	$ 6.93
Production taxes (% of oil, natural gas and NGL sales)	4.7 %	4.9 %	4.9 %
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 7.43	$ 8.26	$ 7.12
Depreciation and amortization expense – other	$ 0.33	$ 0.28	$ 0.35
General and administrative	$ 1.50	$ 1.29	$ 1.50
Impairment of oil and gas properties	$ 2.40	$ —	$ —

Developed and Undeveloped Acreage

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:

	Developed Acres	Undeveloped Acres	Total Acres
Gross	4,710,788	112,620	4,823,408
Net	2,784,586	22,018	2,806,604

Undeveloped Acreage Expirations

The following table sets forth the number of total net undeveloped acres as of December 31, 2025 that will expire in 2026, 2027, 2028, 2029 and 2030 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed. This undeveloped acreage includes approximately 569 acres that PUD locations have been assigned to.

	2026	2027	2028	2029	2030
Total	8,416	2,213	5,796	—	—

Our acreage is located in the Anadarko Basin, Permian Basin and San Juan Basin.

Drilling Results

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.

	Year Ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Operated:						
Productive	37	29.3	58	50.9	91	81.0
Dry holes	—	—	—	—	—	—
Total	37	29.3	58	50.9	91	81.0
Development Wells Non-Operated:						
Productive	25	4.8	51	1.5	19	2.6
Dry holes	—	—	—	—	—	—
Total	25	4.8	51	1.5	19	2.6
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total	—	—	—	—	—	—
Total Wells:						
Productive	62	34.1	109	52.4	110	83.6
Dry holes	—	—	—	—	—	—
Total	62	34.1	109	52.4	110	83.6

The following table sets forth information regarding our drilling activities as of December 31, 2025, including with respect to our operated wells we have begun drilling and those which are drilled and awaiting completion.

	As of December 31, 2025	
	Gross	Net
Drilling	4	2.9
Drilled and Awaiting Completion	3	2.3

As of December 31, 2025, the Company was in process of drilling 4 gross wells (2.9 net) and had finished drilling and was completing or awaiting completion on 3 gross wells (2.3 net). As of December 31, 2025, the Company had no material ongoing non-operated drilling and completion activities.

As of December 31, 2025, we were not a party to any long-term drilling rig contracts.

Productive Wells

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

	Working Interest Assets			Mineral and Royalty Interest Assets		
	Gross	Net	Average Working Interest	Gross	Net	Average Net Revenue Interest
Natural gas	14,095	5,753	41 %	2,720	50	2 %
Oil	6,948	4,373	63 %	651	19	3 %
Total	21,043	10,126	48 %	3,371	69	2 %

Marketing and Customers

We market production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

For the years ended December 31, 2025, 2024 and 2023, purchases by the following companies exceeded 10% of our receipts from oil, natural gas, and NGL sales:

	Year Ended December 31,		
	2025	2024	2023
Purchaser A	23.3 %	32.2 %	52.6 %
Purchaser B	20.6 %	*	12.9 %
Purchaser C	*	12.7 %	*
Purchaser D	*	*	10.4 %

* Purchaser did not account for greater than 10% of oil, natural gas, and NGL sales for the year.

Gathering & Processing Agreements and Firm Transportation

In some areas, we own our own gathering and/or processing assets but in other areas we incur gathering and processing expense under various gathering and/or processing agreements with third-party midstream providers. Only one of our gathering and/or processing agreements includes minimum volume commitments.

We are party to two firm transportation agreements to assist in transporting our natural gas from processing plants to various markets. Any unutilized capacity is monetized if market conditions allow by releasing the capacity to others or transporting third-party gas. For the years ended December 31, 2025, 2024 and 2023 we incurred approximately $0.4 million, $3.4 million and $1.0 million, respectively, of transportation charges under these agreements. As of December 31, 2025, the Company has no material amounts remaining under these agreements.

As part of the IKAV Acquisition (as defined in Note 3), we are now party to a firm sales contract to deliver and sell a certain amount of natural gas at a fixed price of $1.72 per MMbtu through 2030. We expect to fulfill the delivery commitments primarily with production from proved developed reserves. Our production has been sufficient to satisfy the delivery commitments since the acquisition, and we expect our future production will continue to be the primary means of fulfilling the future commitments. However, if our production is not sufficient to satisfy the delivery commitments, we can and may use spot market purchases to satisfy the commitments.

A summary of these volume commitments as of December 31, 2025 is set forth in the table below (in MMbtu):

	December 31, 2025
2026	70,338,571
2027	64,546,373
2028	59,621,628
2029	54,810,356
2030	50,753,106
Total	300,070,034

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.

Seasonality of Business

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.

Title to Properties

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 conduct a thorough title examination 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. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our 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.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

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 many 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 NGL. Such states also have statutes and regulations addressing conservation 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.

The states in which we operate also regulate drilling and operating activities by requiring, among other things, permits for new pad locations, the drilling of wells, best management practices and/or conditions of approval for operating wells, maintaining bonding requirements in order to drill or operate wells, regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. For example, on June 3, 2025, the New Mexico Oil Conservation Division (“OCD”) adopted a set of regulations relating to per- and polyfluoroalkyl substances (“PFAS”), requiring drilling permit applicants to certify that they will not introduce any additives that contain PFAS in the completion of a well. Additionally, on June 20, 2025, Texas passed SB 1150, which requires oil and gas operators to plug wells that have been inactive for at least 15 years.

These laws and regulations may limit the amount of oil, natural gas and NGL 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 Liquids

Sales of 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 NGLs are affected by the availability, terms and cost of transportation. The transportation of NGLs in common carrier pipelines is subject to rate and access regulation. The Federal Energy Regulatory Commission (“FERC”) regulates interstate oil, NGL and other liquid pipeline transportation rates under the Interstate Commerce Act. In general, interstate liquids pipeline rates are set using an annual indexing methodology, however, a pipeline may also use a cost-of-service approach, settlement rates or market-based rates in certain circumstances.

Intrastate liquids pipeline transportation rates 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, vary 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. 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 (the "NGPA") and culminated in the adoption of the Natural Gas Wellhead Decontrol Act, which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 ("NGA") and the NGPA, and by regulations and orders promulgated by FERC. 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 Energy Policy Act of 2005 (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. 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: (i) use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) 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 gatherings, but does apply to activities of gas pipelines and storage companies that provide interstate services. FERC also interprets 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 704, described below. However, in October 2022, the Fifth Circuit ruled that FERC's jurisdiction to regulate market manipulation is limited to interstate transactions only and does not reach intrastate natural gas transactions.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended 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 services, which occur 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 facilities perform a non-jurisdictional gathering function or a jurisdictional transmission 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 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 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 potential litigation, 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 regulation by the U.S. Department of Transportation. The Pipeline and Hazardous Materials Safety Administration ("PHMSA"), an operating administration within the U.S. Department of Transportation, 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 currently unregulated gathering pipelines. The final rule also imposes reporting requirements on all gathering pipelines and specifically requires operators to report safety information to PHMSA. In January 2025, PHMSA issued a pre-publication final rule that requires pipelines, underground natural gas storage facilities, and liquefied natural gas facilities to update leak detection and repair programs to require companies to use commercially available technologies to find and fix methane leaks from pipelines and other facilities; however, the rule was withdrawn prior to publication and future implementation remains uncertain. The future adoption of laws or regulations that apply more comprehensive or stringent safety standards could increase the expenses we incur for gathering service.

In Colorado, on March 17, 2021, the Public Utilities Commission adopted Regulation 11 rules Regulating Pipeline Operators and Gas Pipeline Safety. These regulations apply to all gas public utilities, all municipal or quasi-municipal corporations transporting natural gas or providing natural gas services, all operators of master meter systems, and all operators of pipelines transporting gas in intrastate commerce including gas gathering system operators (certain provisions are tailored to the location and size of the gathering systems involved). The rules require all filed reports to be publicly available and all Notices of Proposed Violation, Notices of Action, pleadings and decisions to be filed publicly. The rules also provide a revised methodology for calculating civil penalties in an effort to provide clarity to both operators and the public. On October 31, 2025, the Colorado Public Utilities Commission issued temporary pipeline safety rules to comply with the statutory deadline set by HB 25-1280. HB25-1280 was passed in 2021 and required the Public Utilities Commission to adopt rules related to gas pipeline safety and repair, including rules for leak detection. The temporary rules issued in November 2025 require more frequent leak surveys and implement new leak classification standards. In Colorado, temporary rules are effective for 210 days from the effective date or until permanent rules become effective. The Colorado Public Utilities Commission is currently planning to issue permanent rules before the end of the 210-day period.

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 EPAct of 2005 and by the Commodity Futures Trading Commission ("CFTC") under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Wall Street Reform and Consumer Protection 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.

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 the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC, PHMSA, the CFTC or state regulatory bodies will take. We do not believe 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 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 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 and 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 possible. 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 sure 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 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 with respect to the release of a “hazardous substance” into the environment. These classes of persons, or, as termed in CERCLA, potentially responsible parties, include the current and past owners or operators of a disposal site or site where the release occurred and anyone who disposed or arranged for the disposal of the hazardous substances found at such sites. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, 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 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 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," which would make such wastes subject 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 Federal Water Pollution Control Act, also known as 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"). The EPA and the Corps issued a final rule on the federal jurisdictional reach over waters of the United States in 2015, which never took effect before being replaced by the Navigable Waters Protection Rule (the "NWPR") in 2020. 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 that based the definition of WOTUS on the pre-2015 definition. Separately, in May 2023, the U.S. Supreme Court's decision in *Sackett v. EPA* invalidated the prior test used by the EPA to determine whether wetlands qualify as navigable waters of the United States, and in September 2023, the EPA and the Corps published a final rule to align the definition of "waters of the United States" with the U.S. Supreme Court's decision in *Sackett v. EPA*. However, roughly half of the states and other plaintiffs are continuing to challenge the September 2023 rule, and the EPA and the Corps are using the pre-2015 definition of WOTUS in these states while litigation continues. 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, 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 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. As a result, substantial uncertainty exists with respect to future implementation of the September 2023 November 2025 proposed rule, the forthcoming 2026 final rule, and the scope of CWA jurisdiction generally. 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. In addition, in an April 2020 decision defining the scope of the CWA that was issued days after the NWPR was published, the U.S. Supreme Court held that, in certain cases, discharges from a point source to a WOTUS through groundwater require a permit if the discharge is the "functional equivalent" of a direct discharge. 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 functional equivalent analysis and the information that should be used to determine which discharges through groundwater may require a permit.

The process for obtaining permits also has the potential to delay our operations. For example, in April 2020, the U.S. District Court for the District of Montana vacated Nationwide Permit ("NWP") 12, the general permit issued by the Corps for pipelines and utility projects. In May 2020, the court narrowed its ruling, vacating and enjoining the use of NWP 12 only as it relates to construction of new oil and gas pipelines. The Corps appealed the decision to the U.S. Court of Appeals for the Ninth Circuit. In July 2020, the U.S. Supreme Court granted in part and denied in part the Corps' application for stay of the order issued by the district court. The U.S. Supreme Court stayed the lower court order except as it applies to the Keystone XL pipeline. In January 2021, the Corps released the final version of a rule renewing twelve NWPs, including NWP 12. The new rule, which took effect in March 2021, split NWP 12 into three parts; NWP 12 will continue to be available to oil and gas pipelines. In March 2022, the Corps published a notice announcing that it is undertaking formal review of NWP 12 and sought public comments. 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. On June 18, 2025, the Corps published a proposal to reissue and modify 56 of its 57 NWPs and introduce a new NWP. NWP 12 would be reissued with only minor clarifying changes. The comment period for the proposed rule closed in July 2025. As a result, any future revisions to NWPs, including NWP 12, are uncertain at this time. 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 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 Energy Policy Act 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.

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. However, in August 2023, the EPA announced that it is reviewing the science underlying the 2020 Ozone NAAQS to determine whether to retain the current ozone NAAQS or implement more stringent standards. The state of Colorado's Denver Metro and North Front Range ("DM/NFR") air quality control region has been unable to attain the 2008 and 2015 NAAQS since their adoption, and its existing nonattainment status for the 2008 NAAQS was reclassified from "serious" to "severe" in 2022 due to violations at area monitors during the 2020 ozone season. The EPA will evaluate DM/NFR's nonattainment status with the 2008 NAAQS in 2027, based on ozone pollution data from between 2024 and 2026. In July 2024, EPA approved Colorado's voluntary request to update its nonattainment classification for the 2015 NAAQS. As a result, DM/NFR was reclassified from a "moderate" to a "serious" nonattainment area. Following voluntary reclassification, EPA will evaluate Colorado's nonattainment status with the 2015 NAAQS in 2032. A "severe" classification triggers significant additional obligations under the CAA and state laws and will result in new and more stringent air quality control requirements applicable to our operations in Colorado and significant operating costs and delays in obtaining necessary permits for new and modified production facilities. In the event the EPA or state agencies implement more stringent standards in the future, we may be subject to more stringent permitting requirements, delays or prohibitions in obtaining such permits, or increased expenditures for pollution control equipment, the cost of which could be significant. 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.

In addition, in November 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule sought to impose emissions reduction standards on both new and existing sources in the oil and natural gas industry, expand the scope of CAA regulation by making regulations in Subpart OOOOa more stringent and creating a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA, and impose emissions reductions targets to meet the stated goals of the U.S. federal administration. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule sought to remove an emissions monitoring exemption for small wellhead-only sites and create a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters." In December 2023, the EPA announced a final rule, later published on March 8, 2024, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. However, in March 2025, the EPA announced its intention to reconsider the March 8, 2024 rule, including Subparts OOOOb and OOOOc, with a final rule expected in or around July 2026. By interim final rule published July 31, 2025, and final rule published on December 3, 2025, EPA gave 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. 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. The December 2025 rule is subject to ongoing litigation but remains in effect. Additionally, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. Consequently, future implementation and enforcement of the final rule remains uncertain at this time.

In January 2025, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued a final rule and submitted it to the Office of the Federal Register for publication requiring pipelines, underground natural gas storage facilities, and liquefied natural gas facilities to update leak detection and repair programs to require companies to use commercially available technologies to find and fix methane leaks from pipelines and other facilities. However, shortly before the rule could be published or become effective, President Trump published an executive order directing federal agencies to immediately withdraw all unpublished rules pending further review and approval. Proposed bill H.R. 4818, introduced in the House of Representatives in July 2025, would codify the January 2025 PHMSA rule, but the bill has not passed to date. Additionally, the Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") has adopted air quality regulations that impose stringent new requirements to control emissions from both existing and new or modified oil and gas facilities in Colorado, including emissions control, monitoring, recordkeeping, and reporting requirements, as well as a Leak Detection and Repair ("LDAR") program for well production facilities and compressor stations. The LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado.

Compliance with these and other air pollution control, air monitoring, gas capture, and permitting requirements has the potential to delay the development of crude oil and natural gas projects and increase our costs of development and production, which costs could be significant.

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. However, in September 2025, EPA proposed to permanently remove program obligations from the Greenhouse Gas Reporting Program for most source categories and suspend program obligations for some sources subject to subpart W (which applies to emission sources in certain segments of the petroleum and natural gas industry) until 2034. Under the proposed rule, facilities in the natural gas distribution segment of subpart W would no longer report to EPA after reporting year 2024.

Given the long-term trend toward increased regulation, future federal GHG regulations of the oil and gas industry remain a possibility. There are also a number of state and regional efforts to regulate emissions of methane from new and existing sources within the oil and natural gas source category. If implemented, compliance with these rules may 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.

In December 2015, the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change (“COP”) in Paris, France, resulted in an agreement for signatory countries to nationally determine their contributions and set GHG emission reduction goals. 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. However, many such initiatives at the international, state and local levels are expected to continue.

The Inflation Reduction Act amended the CAA to include a Methane Emissions and Waste Reduction Incentive Program, which required 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, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. The emissions reported under the Greenhouse Gas Reporting Program would be the basis for any payments under the Methane Emissions Reduction Program. 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. In March 2025, President Trump signed Congress’ Joint Resolution of Disapproval of the Waste Emissions Charge, and in May 2025, EPA issued a final rule to remove the Waste Emissions Charge regulations from the Code of Federal Regulations. Additionally, in July 2025, the One Big Beautiful Bill Act delayed the effective date of the Waste Emissions Charge until 2034. Also, in September 2025, EPA proposed to permanently remove program obligations from the Greenhouse Gas Reporting Program for most source categories and suspend program obligations for some sources subject to subpart W (which applies to emission sources in certain segments of the petroleum and natural gas industry) until 2034. Under the proposed rule, facilities in the natural gas distribution segment of subpart W would no longer report to EPA after reporting year 2024. Consequently, future implementation and enforcement of these rules remains uncertain at this time.

Separately, many U.S. state and local leaders and foreign governments have intensified or stated their intent to intensify efforts to support international climate commitments and treaties and have developed programs that are aimed at reducing GHG emissions, such as by means of cap-and-trade programs, carbon taxes, encouraging the use of renewable energy or alternative low-carbon fuels or imposing new climate-related reporting requirements. Cap-and-trade programs, for example, typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

Financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. The Federal Reserve in 2020 announced that it joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In 2022, the Federal Reserve launched a pilot climate scenario analysis exercise to learn about certain large banking organizations’ climate risk-management practices and challenges and help ensure that supervised institutions are appropriately managing material financial risks related to climate change. In January 2025, the Federal Reserve announced its withdrawal from the Network for Greening the Financial System. However, any limitation of investments in and financing for fossil fuel energy companies, including at the international level, could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Further, the 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 such initiatives at the international, state and local levels are expected to continue and any legislation or regulatory programs aimed at reducing GHG emissions, addressing climate change more generally or requiring the disclosure of climate-related information could increase the cost of consuming, and thereby reduce demand for, the natural gas we produce 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, typically by state natural gas commissions, 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. For example, Colorado Senate Bill 19-181 amended state law to give municipalities and counties greater local control over siting and permitting of oil and gas locations, and some municipalities within the state have implemented regulations within their jurisdictions. Any successful bans or moratoria where we operate, whether at the state or local level, could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations which could adversely impact our ability to develop our reserves. In addition, in light of concerns about seismic activity potentially being triggered by the injection of produced waters into underground wells, regulators in the states in which we operate have adopted additional requirements related to seismic safety for hydraulic fracturing activities or the underground injection of fluid wastes. For example, the regulations that the Colorado Energy & Carbon Management Commission (“ECMC”) adopted in November 2020 impose various requirements on the underground injection of fluid wastes to further seismic safety and protect the environment. In 2021, ECMC provided a guidance document outlining the seismic activity requirements for underground injection, with the baseline of identifying geologic hazards within a 1-mile radius using a geologic hazard map. If geologic hazards are identified, then the project will need to proceed with the preparation of a Geologic Hazard Plan. 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.

If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and attendant permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential legislation or regulation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

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 waters of the U.S. 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 agency 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). These regulations are subject to ongoing litigation in several federal district courts, and 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 in April 2022, and generally restored provisions that were in effect prior to 2020. In May 2024, the CEQ finalized the Phase II rule that accelerates NEPA reviews while maintaining consideration of relevant environmental, climate change and environmental justice effects of a proposed project. However, several states and environmental groups have filed challenges to the Phase II rule in federal district court. Further, the Infrastructure and Investment Jobs Act signed into law in November 2021, codified some of the July 2020 amendments in statutory text. 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 January 2025, President Trump issued an executive order requiring CEQ to provide guidance on implementing NEPA and to propose rescinding and replacing CEQ's NEPA regulations with implementing regulations at the agency level. The executive order also instructs federal agencies to adhere to only the relevant legislated requirements for environmental reviews and to prioritize efficiency and certainty over any other objectives in such reviews. In February 2025, CEQ sent an interim final rule to the White House Office of Management and Budget that would immediately withdraw the NEPA implementing regulations. In January 2026, CEQ formally repealed its NEPA implementing regulations on the basis of the Supreme Court's decision in Seven County Infrastructure Coalition v. Eagle County, Colorado. In Seven County, the Supreme Court directed lower courts to give "substantial deference" to reasonable agency conclusions underlying its NEPA process. Accordingly, the January 2026 rule is meant to streamline NEPA review, and has left the July 2020, Phase I, and Phase 2 rules in place. The January 2026 rule may be subject to litigation. Also in January 2026, CEQ issued guidance for agencies undergoing NEPA review for emergency actions. 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. Although the SPEED Act has passed the House of Representatives, final passage and implementation remains uncertain. The potential impact of further 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 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. In January 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. 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 Trump-era regulations concerning the definition of "habitat" and critical habitat exclusions. In April 2024, the FWS finalized three rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. In August 2024, environmental groups challenged the new ESA regulations in federal district court, which litigation remains ongoing. However, in April 2025, the FWS and National Marine Fisheries Service proposed to redefine "harm" to mean affirmative acts that are directed immediately and intentionally against a particular animal, excluding acts or omissions that indirectly cause injury. Additionally, in November 2025, the Trump Administration proposed several rules that would significantly alter ESA protections for plants and animals. One proposed rule would rescind a rule that automatically extends protections for endangered species to threatened species. Another proposed rule would change regulations for listing species as endangered or threatened as well as for designating critical habitats. Additionally, a third proposed rule would reinstate the framework for evaluating the benefits and cost of designating a critical habitat by considering factors like economic impact, impact on national security, and other relevant impacts. The U.S. Fish and Wildlife Service is expected to issue final rules in 2026. 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, and it is possible the new rules could increase the portion of our lease areas that could be designated as critical habitat. 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. However, in January 2025, the Trump administration issued an executive order directing (i) agencies to use, to the maximum extent permissible, the ESA regulation on consultations in emergencies, to facilitate the domestic energy supply and (ii) the Endangered Species Act Committee to meet at least quarterly to ensure a prompt and efficient review of all submissions for potential actions that could facilitate energy development.

The MBTA 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 United States. 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, the Department of the Interior has not yet issued proposed regulations. However, in April 2025, the U.S. Department of Interior issued a memo, M-37085, to repeal M-37065, which had previously declared that the Migratory Bird Treaty Act prohibited both the intentional and incidental "take" of migratory birds. The memo restored M-37050, clarifying that only the intentional "take" of migratory birds is prohibited. 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 a critical or suitable habitat, it could adversely impact the value of our leases. 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.

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, whose purpose 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 provide a safe, healthy, respectful, and fair workplace for all employees. We believe our employees' talent and wellbeing is foundational to delivering on our corporate strategy, and that intentional human capital management strategies enable us to attract, develop, retain and reward our dedicated employees.

As of December 31, 2025, Mach Resources had 840 total employees, all of which were full-time employees. From time to time, we utilize the services of independent contractors to perform various field and other services. Neither we nor Mach Resources are a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. In general, we believe that employee relations are satisfactory.

Employee Safety and Health

The health, safety, and well-being or our employees is a top priority. In addition to our commitment to complying with all applicable safety, health, and environmental laws and regulations, we are focused on minimizing the risk of workplace incidents and preparing for emergencies as a priority element of our culture. We work to reduce safety incidents in our business and actively seek opportunities to make safety culture and procedural improvements.

Item 1A. Risk Factors

Our business involves a high degree of risk. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Additionally, new risks may emerge at any time, and we cannot predict those risks or estimate the extent to which they may affect financial performance.

If any of the following risks actually occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline, and our unitholders could lose all or part of their investment.

Risks Related to Cash Distributions

We may not have sufficient available cash to pay any quarterly distribution on our common units following the payment of expenses, funding of development costs and establishment of cash reserves.

We may not have sufficient available cash each quarter to pay distributions on our common units. Under the terms of our partnership agreement, the amount of cash available for distribution will be reduced by our operating expenses, cash interest, development costs and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development, optimization and exploitation of our oil and natural gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of available cash that we distribute to our unitholders will depend principally on the cash we generate from operations, which will depend on, among other factors:

- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our oil, natural gas and NGL production;
- the amount and timing of settlements on our commodity derivative contracts;
- the level of our capital expenditures, including scheduled and unexpected maintenance expenditures;
- the level of our operating costs, including payments to our general partner and its affiliates for general and administrative expenses;
- the restrictive covenants in the New Credit Agreement and other agreements governing indebtedness that limit our ability to pay dividends or distributions in respect of our equity; and
- the level of our interest expenses, which will depend on the amount of our outstanding indebtedness and the applicable interest rate.

Furthermore, the amount of cash we have available for distribution depends primarily on our cash flow, including cash from financial reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

The amount of our quarterly cash distributions from our available cash, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Our future business performance may be volatile, and our cash flows may be unstable. We do not have a minimum quarterly distribution. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, future quarterly distributions paid to our unitholders will vary significantly from quarter to quarter and may be zero.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.

Our revenues, operating results, cash available for distribution, 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. 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 the potential impact of any significant new tariffs;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- actions of 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;
- 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 oil, natural gas and NGL inventories;
- the level of U.S. LNG exports;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events;
- prevailing prices on local price indexes in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and processing 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;
- changes in ocean freight capacity, which could adversely impact LNG shipping capacity or lead to material interruptions in service or stoppages in LNG transportation;
- political and economic conditions in or affecting major LNG consumption regions or countries, particularly Asia and Europe;
- weather conditions and natural disasters, including those influenced by climate change;
- technological advances affecting energy consumption;
- the impact of energy conservation efforts;
- the price and availability of alternative fuels;

- activities to restrict the exploration, development and production of oil and natural gas to minimize greenhouse gas (“GHG”) emissions;
- speculative trading in oil and natural gas derivative contracts;
- increased end-user conservation;
- U.S. trade policies and their effect on U.S. oil and natural gas exports;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes, including legislation or regulations addressing GHG emissions or requiring the reporting of GHG emissions or climate-related information.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements accurately. 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 and reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower than current WTI and Henry Hub 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, cash available for distribution, liquidity and ability to meet our financial commitments or cause us to delay our planned capital expenditures.

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, acid, 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;
- any future lack of available capacity on interconnecting transmission pipelines;
- delays imposed by, or resulting from, compliance with regulatory requirements, including limitations on freshwater sourcing, wastewater disposal, emissions of GHGs and hydraulic fracturing;
- pressure or irregularities in geological formations;
- limited availability of financing on acceptable terms;
- issues related to 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 air, surface and subsurface 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;
- lack of available gathering facilities or delays in construction of gathering facilities;
- adverse weather conditions, such as hurricanes, lightning storms, flooding, tornadoes, snow or ice storms and changes in weather patterns;
- the availability and timely issuance of required governmental permits and licenses;
- title issues or legal disputes regarding leasehold rights; and
- other market limitations in our industry.

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 internal estimation of our future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, 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 and acid used for acid stimulation, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution and disposal 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 and natural gas from these or any other drilling locations. As such, our actual drilling activities may materially differ from those presently identified.

As a result of the limitations described in this Annual Report, we may be unable to drill many of our identified locations. In addition, although we plan to fund our drilling program entirely with cash flow from operations, if our cash flows are less than we expect or we alter our drilling plans, we may be required to borrow more under the New Credit Agreement than we expect or issue new 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. 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 in turn could have a material adverse effect on the borrowing base under the New Credit Agreement or our future business and results of operations. Additionally, if we curtail or cancel our drilling program, we may be required to reduce our estimated proved reserves, which could in turn reduce the borrowing base under the New Credit Agreement.

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

Properties that we decide to drill that do not yield oil or 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 or natural gas 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 or natural gas will be present or, if present, whether oil or natural gas 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.

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 oil and natural gas properties requires us to assess recoverable reserves, future oil and natural gas 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, but such a review may not reveal all existing or potential problems. Such assessments are inexact and inherently uncertain. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as any groundwater contamination or pipe corrosion, when a review is performed. We also may be unable to obtain contractual indemnities from the seller for liabilities arising 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. For these reasons, the properties we have acquired or will acquire in the future may not produce as expected or may not increase our cash available for distribution.

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

As of December 31, 2025, approximately 7% of our total estimated proved reserves were classified as PUDs using SEC Pricing. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Estimated future development costs relating to the development of our PUDs on December 31, 2025 were approximately $1.1 billion over the next five years. Our ability to fund these expenditures is subject to a number of risks. 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 PUDs, 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 undeveloped reserves to developed reserves or that our PUDs 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.

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.

Difficulties that we face while completing our wells include:

- the ability to fracture stimulate the planned number of stages with the planned amount of proppant;
- the ability to source acid for our acid stimulation completion techniques;
- 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. 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.

The marketability of our production is dependent upon gathering, treating, processing and transportation facilities, some of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues could decrease.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of gathering, treating, processing and transportation pipelines, plants and other midstream facilities, a significant portion of which is owned by third parties. Some of our oil and natural gas production is collected from the wellhead by third-party gathering lines and transported to a gas processing or treating facility or transmission pipeline. We do not control these third-party facilities and our access to them may be limited, curtailed or denied. 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. The 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 in the properties we do not operate to support the construction of pipeline facilities by third parties or a significant disruption in the availability of our or third-party midstream facilities or other production facilities could adversely impact our ability to deliver to market or produce our natural gas and thereby causing a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement gathering, treating, processing 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 oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

If third-party pipelines or other midstream facilities interconnected to our gathering systems become partially or fully unavailable, our revenues and cash flows and our ability to make cash distributions to our unitholders could be materially adversely affected.

Our gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and/or on short notice. If any of these pipelines or other midstream facilities become unavailable for any reason, or, if these third parties are otherwise unwilling to receive or transport the oil, natural gas and produced water that we gather and/or process, our revenues, cash flows and ability to make cash distributions to our unitholders could be materially adversely affected.

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 and natural gas 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, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas 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 change could materially affect the estimated quantities and present value of our reserves. Furthermore, our development plan calls for completing horizontal wells using tighter well spacing and acid stimulation, 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 or that our proved undeveloped reserves will be developed within the periods anticipated.

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 standardized measure of proved reserves and PV-10 values of our estimated reserves are accurate estimates of the current fair value of our estimated oil, natural gas and NGL reserves.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, may not represent the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. For example, our estimated proved reserves as of December 31, 2025 were calculated under SEC rules using the unweighted arithmetic average first day of the month prices for the prior 12 months of $3.39/MMBtu for natural gas and $65.34/Bbl for oil at December 31, 2025, which, for certain periods during this period, were substantially different from the available spot prices. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with Accounting Standards Codification 932, “Extractive Activities — Oil and Gas,” may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Unless we replace our produced reserves with acquired or developed new reserves, our reserves and production will decline, which would adversely affect our future cash flows, results of operations and cash available for distribution.

Producing oil and natural gas 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.

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

Our ability to acquire additional oil and natural 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 natural gas 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 oil and natural gas properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Those larger companies may also have a greater ability to continue development activities during periods of low oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. 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 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.

Our midstream services contracts are generally structured as short-term and long-term, fixed-fee contracts, which may negatively impact our operating margins and cash flow during periods of lower oil and natural gas prices.

We have entered into short-term and long-term, fixed-fee contracts with third parties for gathering, processing and transportation services, including some firm transportation contracts. Under these short-term and long-term, fixed-fee arrangements, our gathering and processing expenses are generally fixed on a per unit basis for the term of the applicable contract and do not automatically adjust in response to a decline in oil and natural gas prices. In the event of a prolonged period of lower commodity prices, our revenue will decline while the per unit fees we pay for natural gas gathering, treating and compression services generally will not, which would negatively impact our operating margins and cash flow. In addition, during periods of depressed oil and natural gas prices, the market prices for such services may be lower than what we are contractually obligated to pay to our current third-party midstream service providers. Furthermore, to the extent certain future taxes or assessments are imposed on certain midstream assets we utilize, under certain circumstances we may be required by our midstream services contracts to reimburse the midstream service provider for such taxes or assessments, which could negatively affect our operating margins and cash flow. Our third-party midstream service providers are under no obligation to renegotiate their contracts with us. Our failure to obtain these services on competitive terms could materially harm 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.

We depend on Mach Resources to provide us services necessary to operate our business. If Mach Resources were unable or unwilling to provide these services, it would result in a disruption in our business that could have an adverse effect on our financial position, financial results and cash flow.

We do not directly employ directors, officers or employees. Pursuant to the new management services agreement entered into with Mach Resources on October 27, 2023 in connection with the closing of the Offering (the "MSA"), an entity that is wholly owned by Tom L. Ward and his family, all of our executive management personnel are employees of Mach Resources, and we use a significant number of Mach Resources' employees to operate our properties and provide us with general and administrative services. If Mach Resources were to become unable or unwilling to provide such services, we would need to develop these services internally or arrange for the services from another service provider. Developing the capabilities internally or by retaining another service provider could have an adverse effect on our business, and the services, when developed or retained, may not be of the same quality as provided to us by Mach Resources. Additionally, if the MSA were to terminate, we would lose our key personnel.

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. 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.

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.

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 99% of our acreage is held by existing production, the remaining acreage is subject to expiration. 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.

We own non-operating interests in properties developed and operated by third parties and some of our leasehold acreage could be pooled by a third-party operator. As a result, we are unable, or may become unable as a result of pooling, to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other contractual arrangements. Similarly, our acreage in Oklahoma and Texas may be pooled by third-party operators under state law. If our acreage is involuntarily pooled under state forced pooling statutes, it would reduce our control over such acreage, and we could lose operatorship over a portion of our acreage that we plan to develop.

We may not be able to maximize the value associated with acreage that we own but do not operate in the manner we believe appropriate, or at all. We cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator's operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our business, financial condition and results of operations.

We may be unable to make accretive acquisitions or may make opportunistic dispositions. Any such acquisitions, if not integrated or conducted successfully, or such dispositions, if not conducted successfully, may disrupt our business and hinder our growth potential.

We may be unable to make accretive acquisitions or may make opportunistic dispositions. Any such acquisitions, if not integrated or conducted successfully, or such dispositions, if not conducted successfully, may disrupt our business and hinder our growth potential. Our ability to grow and to increase distributions to our unitholders depends in part on our ability to make acquisitions that result in an increase in cash available for distribution. In the future we may make acquisitions of assets or businesses that complement or expand our current business. There is intense competition for acquisition opportunities in our industry and we may not be able to identify attractive acquisition opportunities. 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. In addition, from time to time, we may consider opportunistic dispositions, including dispositions of non-operating properties, having the potential to further limit future production.

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, the New Credit Agreement imposes certain limitations on our ability to enter into mergers or combination transactions and to incur certain indebtedness, which could limit our ability to acquire assets and businesses.

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. 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 expected elections by working interest partners, drilling and completion costs, midstream service costs, oil and natural gas 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 more under credit facility than we expect 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 the New Credit Agreement, the issuance of additional 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, our development plan, acquisitions and cash distributions to unitholders. Additionally, the market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our capital expenditures with the issuance of additional equity. The issuance of additional equity securities may be dilutive to our unitholders The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things: oil and natural gas prices; actual drilling results; the availability and cost of drilling rigs and labor 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 the New Credit Agreement; and
- our ability to access the debt and equity capital markets or sell non-core assets.

If our revenues or the borrowing bases under the New Credit Agreement 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 the New Credit Agreement 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.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our business strategy and cash flows.

Changes in the global trade environment, including the imposition of tariffs, could adversely affect our business.

Escalating trade tensions, particularly between the U.S. and Canada, Mexico, China and other countries, may lead to the imposition of tariffs and trade restrictions. We may be materially adversely impacted by tariffs if we are not able to adapt our supply chain strategy. We may also face unanticipated costs in developing our domestic supply chain and increased competition for materials and components in the United States, which also would impact our business and results of operations. The imposition of tariffs may also create uncertainty in our industry. Increases in costs to drill and develop reserves as a result of tariffs coupled with lower commodity prices from increased domestic production could make producing such reserves no longer economically viable or technically feasible. Additionally, existing or future tariffs may negatively affect our customers, suppliers, and manufacturing partners. Such outcomes could adversely affect the amount or timing of our revenues, results of operations or cash flows, and continuing uncertainty could cause sales volatility and price fluctuations. Tariffs, the adoption and expansion of trade restrictions, the occurrence of a trade war, or other governmental action related to tariffs, trade agreements or related policies have the potential to adversely impact our supply chain and access to equipment, and our costs and ability to economically serve certain markets. Any such cost increases or decreases in availability could slow our growth and cause our financial results and operational metrics to suffer. There is uncertainty about the future relationship between the United States and other countries with respect to trade policies, taxes, government regulations, and tariffs and we cannot predict whether, and to what extent, U.S. trade policies will change in the future.

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, 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 United States. 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 or acid used for acid stimulation, and 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, profitability and ability to make distributions to our unitholders may be materially adversely impacted.

The unavailability or high cost of drilling rigs, frac 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, frac crews, pipe and other equipment and supplies, including sand and other proppant used in hydraulic fracturing operations and acid used for acid stimulation, as well as for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with commodity prices or drilling activity in our areas of operation and in other shale basins in the United States, 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 net production volumes being below our forecasted volumes. In addition, any such negative effect on net production volumes, or significant increases in costs could have a material adverse effect on our cash flow and profitability.

We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

For the year ended December 31, 2025, two purchasers each accounted for more than 10% of our revenue: Phillips 66 Company (23.3%) and NextEra Energy Marketing, LLC (20.6%). We do not have long-term contracts with our customers; rather, we sell the substantial majority of our production contracts with terms of 12 months or less, including on a month-to-month basis, to a relatively small number of customers. The loss of any one of these purchasers, the inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation could materially adversely affect our financial condition, results of operations and ability to make distributions to our unitholders. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have ready access to suitable markets for our future production. See "Business and Properties — Marketing and Customers" included in Items 1 and 2 of Part I of this Annual Report.

The availability of a ready market for any hydrocarbons we produce depends on numerous factors beyond our control, including, but not limited to, the extent of domestic production and imports of oil, the proximity and capacity of oil, natural gas and NGL pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil, natural gas and NGL production and federal regulation of oil, natural gas and NGLs sold in interstate commerce.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

As of December 31, 2025, we had $1.15 billion outstanding under our New Credit Agreement. In the future, we and our subsidiaries may incur substantial additional indebtedness. The New Credit Agreement contains restrictions on the incurrence of additional indebtedness, and these restrictions will be subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial. Additionally, the New Credit Agreement permits us to incur certain amounts of additional indebtedness.

Our level of indebtedness could affect our operations in several ways, including the following:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our debt, thereby reducing the cash available to finance our operating and investing activities;
- limiting management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increasing our vulnerability to downturns and adverse developments in our business and industry;
- limiting our ability to raise capital on favorable terms;
- limiting our ability to raise available financing, make investments, lease equipment, sell assets and engage in business combinations;
- making us vulnerable to increases in interest rates;
- putting us at a competitive disadvantage relative to our competitors; and
- limiting our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities, due to covenants contained in our New Credit Agreement, including financial covenants.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

The New Credit Agreement contains a number of significant covenants, including restrictive covenants that, subject to certain qualifications, limit our ability to, among other things:

- make certain payments, including paying dividends or distributions in respect of our equity;
- incur additional indebtedness;
- make loans to others;
- make certain acquisitions and investments;
- make or pay distributions on our common units, if an event of default or borrowing base deficiency exists;
- merge or consolidate with another entity;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, the New Credit Agreement requires us to maintain compliance with certain financial covenants.

The restrictions in the New Credit Agreement also impact our ability to obtain capital to withstand a downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our debt arrangements may impose on us.

A breach of any covenant in the New Credit Agreement will result in a default under our New Credit Agreement and an event of default if there is no grace period or if such default is not cured during any applicable grace period. An event of default, if not waived, could result in acceleration of the indebtedness outstanding under the applicable agreement and in an event of default with respect to, and an acceleration of, the indebtedness outstanding under any other debt agreements to which we are a party. Any such accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Any significant reduction in our borrowing base under the New Credit Agreement as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

The New Credit Agreement limits the amounts we can borrow up to certain borrowing base amounts, which the administrative agent in good faith and in accordance with its usual and customary procedures for evaluating oil and gas loans and related assets at that particular time and otherwise acting in its sole discretion, will determine and which will be approved by the required lenders or all lenders, as applicable in the case of an increase in the borrowing base, on a semi-annual basis based upon projected revenues from our natural gas properties, our commodity derivative contracts securing our loan and certain other information (including, without limitation, the status of title information with respect to the oil and natural gas properties and the existence of any other indebtedness, liabilities, fixed charges, cash flow, business, properties, prospects, management and ownership, hedged and unhedged exposure to price, price and production scenarios, interest rate and operating cost changes). In addition to the scheduled redeterminations, the Company and the required lenders may request unscheduled interim redeterminations of the borrowing base not more than once between scheduled redeterminations. Any increase in the borrowing base will require the consent of all lenders (other than defaulting lenders). If the requisite number of required lenders or all lenders, as applicable in the case of an increase in the borrowing base, do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. We will be required to repay outstanding borrowings in excess of the borrowing base. The borrowing base may also automatically decrease upon the occurrence of certain events.

In the future, we may not be able to access adequate funding under the New Credit Agreement as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a 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 a defaulting lender’s portion. Furthermore, our borrowing base may be reduced if we sell assets in the future. Declines in commodity prices could result in a determination to lower the borrowing base and, in such a 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 drilling and development plan, make acquisitions, make distributions to our unitholders or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

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

Borrowings under the New Credit Agreement bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our business, financial condition and results of operations and cash available for distribution remain unchanged.

The credit risk of financial institutions could adversely affect us.

We have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies and deposit accounts held at regional banks. In addition, if any lender under the New Credit Agreement is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender’s commitment under the credit agreement.

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 the New Credit Agreement 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 the New Credit Agreement 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 carry out our development plan, our cash available for distribution and operating results.

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 and natural gas, we enter into derivative contracts for a portion of our projected oil and natural gas production, primarily consisting of swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosure About Market Risk — Commodity price risk — Commodity 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 regarding 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, make payments on our indebtedness and make distributions to our unitholders, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties and oil and natural gas prices.

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

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.

Events outside of our control, including widespread public health crises, epidemics and outbreaks of infectious diseases, or the threat thereof, and any related threats of recession and other economic repercussions could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

Widespread public health crises, epidemics, and outbreaks of infectious diseases, which can give rise to a threat of recession and related economic repercussions can create significant volatility, uncertainty and turmoil in the global economy and oil and gas industry. These variables are beyond our control and may have the effect of disrupting the normal operations of many businesses, including the temporary closure or scale-back of business operations and/or the imposition of either quarantine or remote work or meeting requirements for employees, either by government order or on a voluntary basis. Widespread public health crises, epidemics and outbreaks of infectious diseases spreading throughout the U.S. and globally could result in significant disruptions to our operations. The global economy, our markets and our business have been, and may continue to be, materially and adversely affected by widespread public health crises, epidemics and outbreaks of infectious diseases, which could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, supply chain disruptions, the potential for significant new tariffs, increased demand, labor shortages associated with a fully employed U.S. labor force, geopolitical issues, inflation, the availability and cost of credit and the United States financial market and other factors have contributed to increased economic uncertainty and diminished expectations for the global economy. Between 2022 and 2024, the Federal Reserve raised the target range for the federal funds rate in an effort to curb inflation. As of December 31, 2025, the Federal Reserve's target range for the federal funds rate was 3.50% to 3.75% in light of the progress on inflation. In December 2025, inflation was 2.7%. We continue to undertake actions and implement plans to strengthen our supply chain to address these pressures and protect the requisite access to commodities and services.

Nevertheless, we expect for the foreseeable future to experience supply chain constraints and inflationary pressure on our cost structure. We also may face shortages of these commodities and labor, which may prevent us from fully executing our development plan. These supply chain constraints and inflationary pressures will likely continue to adversely impact our operating costs and, if we are unable to manage our supply chain, it may impact our ability to procure materials and equipment in a timely and cost-effective manner, if at all, which could impact our ability to distribute available cash and result in reduced margins and production delays and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

We continue to take actions to mitigate supply chain and inflationary pressures. We are working closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical suppliers which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient.

In addition, continued hostilities related to the Russian invasion of Ukraine and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors and other factors, such as decreased demand from China, combined with volatile commodity prices, and declining business and consumer confidence may contribute to an economic slowdown and a recession. Recent growing concerns about global economic growth have had a significant adverse 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 ultimately adversely impact our business, financial condition and results of operations.

Additionally, an unpredictable or volatile political environment in the United States, including any social unrest and uncertainty as a result of the 2024 U.S. presidential election, could negatively impact business and market conditions, economic growth, financial stability and business, consumer, investor and regulatory sentiments, any one or more of which could have a material adverse impact on our financial condition and results of operations. It is difficult to predict the legislative and regulatory changes that may result due to the new administration. The new administration and make-up of the Senate and/or House of Representatives may cause broader economic changes due to changes in governing ideology and style. New appointments to the Board of Governances of the Federal Reserve could affect monetary policy and interest rates, which could in turn affect economic growth.

Oil and gas exploration and production companies are frequently subject to litigation claims from landowners, royalty owners and other interested parties, particularly during periods of declining commodity prices.

Title to oil and natural gas properties is often unclear and subject to claims by third parties. Additionally, oil and gas companies are frequently subject to claims with respect to underpayment of royalties, environmental hazards and contested ownership of properties, especially during periods of declining commodity prices and therefore revenue and royalty payments. The oil and gas exploration and production business is especially susceptible to increased cost of capital, hedging losses and declining revenues which can result in defaults on third-party obligations. These risks and others can result in the incurrence of significant attorney's fees and other expenses incurred in the prosecution or defense of litigation.

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 operations are subject to all of the risks associated with drilling for and producing oil, natural gas and NGLs and operating gathering and processing facilities including the possibility of:

- environmental hazards, such as releases of pollutants into the environment, including groundwater, surface water, soil and air;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- ruptures, fires and explosions;
- damage to pipelines, processing plants, compression assets, water infrastructure, and related equipment and surrounding properties caused by tornadoes, floods, freezes, fires and other natural disasters;
- inadvertent damage from construction, vehicles and farm and utility equipment;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas 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 by government agencies or third parties for:

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

These events may also result in curtailment or suspension of our gathering and processing facilities. A natural disaster or any event such as those described above affecting the areas in which we and our third-party customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to us and our third-party customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on portions or all of our gathering facilities.

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, in some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, including for pollution and other environmental risks. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Extreme weather conditions and the physical risks of climate change could adversely affect our ability to conduct drilling activities in the areas where we operate and the operations of our gathering and processing facilities and have a negative impact on our business and results of operations.

The majority of the scientific community has concluded that climate change may result in more frequent and/or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, which could affect some, or all, of our operations. If any such effects were to occur, they could adversely affect or delay demand for oil or natural gas products or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves, which may not be fully insured. For example, our development, optimization and exploitation activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes, thunderstorms, tornadoes and snow or ice storms, or other climate-related events such as wildfires and floods, in each case which may cause a loss of operational efficiency or production from temporary cessation of activity or lost or damaged facilities and equipment. Further, these types of interruptions could result in a decrease in the volumes supplied to our gathering systems, and delays and shutdowns caused by severe weather may have a material negative impact on the continuous operations of our gathering and processing facilities, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our third-party customers and thereby give rise to certain termination rights or other liabilities under our contracts. Such extreme weather conditions and events could also impact other areas of our operations, including the costs or availability of insurance, access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary resources, such as water, and third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning.

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

Increased attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on combating climate change, together with changes in consumer and industrial/commercial behavior, societal pressure on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in the enactment of climate change-related regulations, policies and initiatives at the government, regulator, corporate and/or investor community levels, including alternative energy requirements, new fuel consumption standards, energy conservation, enhanced disclosure obligations and emissions reductions measures and responsible energy development; technological advances with respect to the generation, transmission, storage and consumption of energy (including advances in wind, solar and hydrogen power, as well as battery technology); increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles); and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services. These developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, oil and natural gas products. Such developments may also adversely impact, among other things, our stock price and access to capital markets, and the availability to us of necessary third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to successfully carry out our business strategy. Climate change-related developments may also impact the market prices of or our access to raw materials such as energy and water and therefore result in increased costs to our business.

More broadly, the enactment of climate change-related legislation and regulatory initiatives may in the future result in increases in our compliance costs and other operating costs. For further discussion regarding the risks posed to us by climate change-related legislation and regulatory initiatives, see "— Climate change legislation or regulations restricting emissions of GHGs or requiring the reporting of GHG emissions or climate-related information could result in increased operating costs, impact the demand for the oil and natural gas we produce, and adversely affect our business."

Negative perceptions regarding the Company's industry and related reputational risks may also in the future adversely affect the Company's ability to successfully carry out the Company's business strategy by adversely affecting the Company's access to capital. There have been efforts, 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. Certain financial institutions and members of the investment community have shifted, and others may elect in the future to shift, some or all of their investment into non-fossil fuel related sectors. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Certain investment banks and asset managers 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, such as the Company, have also become 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, this could make it more difficult to secure funding for exploration and production activities or adversely impact the cost of capital for both the Company and its customers, and could thereby adversely affect the demand and price of the Company's securities. Limitation of investments in and financings for energy companies could also result in the restriction, delay, or cancellation of infrastructure projects and energy production activities.

Further, negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change or other sustainability-related matters, may also lead to increased reputational and litigation risk and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new laws, regulations, guidelines and enforcement interpretations targeting our industry. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations, and such activism could materially and adversely impact our ability to operate our business and raise capital. The foregoing factors may result in downward pressure on the stock prices of oil and gas companies, including the Company's, and cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. For example, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas, or claims alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers. Although the Company is not a party to any such litigation, we could be named in actions making similar allegations, which could lead to costs and materially impact our financial condition in an adverse way.

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

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, the release, disposal or discharge of materials into the environment, and occupational health and safety aspects of our operations. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated drilling activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; the prohibition of noise-producing activities; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including threatened and endangered species habitats; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. We may be required to make significant capital and operating expenditures or perform remedial or other corrective actions at our wells and properties to comply with the requirements of these environmental laws and regulations or the terms or conditions of permits issued pursuant to such requirements. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations (including plugging and abandonment obligations) and waste disposal practices. Spills or other releases of regulated substances, including such spills and releases that could occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. For example, lawsuits in which landowners sue every operator in the chain of title for environmental damages to their property are not uncommon in states in which we operate. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In certain instances, citizen groups also have the ability to bring legal proceedings against us regarding our compliance with environmental laws, or to challenge our ability to receive environmental permits that we need to operate. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations or historical oil and natural gas production in our areas of operation, which have been producing oil in certain instances for several decades. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

The long-term trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. For example, in January 2021, the Biden administration directed the U.S. Department of the Interior ("DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed subject to certain limitations. In August 2022, the U.S. Court of Appeals vacated and remanded the federal district court's decision to block the pause on new oil and gas leasing, and the federal district court shortly thereafter enjoined the DOI from implementing the pause in the thirteen states that had challenged the pause, including Oklahoma and Texas. Litigation over leasing remains ongoing. However, in January 2025, President Trump issued executive orders (i) reversing the Biden administration's leasing pause and executive orders withdrawing certain lands and waters from federal oil and gas leasing and (ii) directing all federal agencies to facilitate the leasing, siting, and generation of domestic energy resources, including on federal lands and waters. In addition, in November 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule sought to impose emissions reduction standards on both new and existing sources in the oil and natural gas industry, expand the scope of Clean Air Act ("CAA") regulation by making regulations in Subpart OOOOa more stringent and creating a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA. In addition, the proposed rule sought to establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule sought to remove an emissions monitoring exemption for small wellhead-only sites and create a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters," triggering certain investigation and repair requirements. In December 2023, the EPA announced a final rule, later published on March 8, 2024, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. 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. Accordingly, in March 2025, EPA announced its intention to reconsider the Marh 8, 2024 ule, including Suparts OOOOb and OOOOc. By interim final rule published on July 3, 2025, and final rule published on December 3, 2025, EPA provided extensions for most compliance deadlines for equipment, leaks, and state plans under OOOOb and OOOOc to January 22, 2027. A final EPA rule reconsidering requirements promulgated under OOOOb and OOOOc is expected in or around July 2026. Consequently, future implementation and enforcement of the final rule remains uncertain at this time. Further, in August 2022, the Inflation Reduction Act of 2022 was signed into law, which incentivized the reduction of methane emissions by imposing a fee on methane produced by petroleum and natural gas facilities in excess of a specified threshold, among other initiatives. The Inflation Reduction Act amended the CAA to include a Methane Emissions and Waste Reduction Incentive Program, which required 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, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. The emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the Methane Emissions Reduction Program. Also in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the process to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. In March 2025, President Trump signed Congress' Joint Resolution of Disapproval of the Waste Emissions Charge, and in May 2025, EPA issued a final rule to remove the Waste Emissions Charge regulations from the Code of Federal Regulations. Additionally, the One Big Beautiful Bill Act of 2025 delayed the effective date of the WEC until 2034. EPA, in September 2025, also proposed to permanently remove program obligations from the Greenhouse Gas Reporting Program for most source categories and suspend program obligations for some sources subject to subpart W (which applies to emission sources in certain segments of the petroleum and natural gas industry) until 2034. Consequently, future implementation and enforcement of these rules remains uncertain at this time. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry as well as our own results of operations, competitive position or financial condition. While the Supreme Court's decision in *Loper Bright Enterprises v. Raimondo* ("*Loper*") to overrule *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.* ("*Chevron*") and end the concept of general deference to regulatory agency interpretations of laws introduces new complexity for federal agencies and administration of climate change policy and regulatory programs, many of these initiatives are expected to continue. Consequently, legislation and regulatory programs to address climate change or reduce emissions of GHGs could have a material adverse effect on our business, financial condition or results of operations.

To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Climate change legislation or regulations restricting emissions of GHGs or requiring the reporting of GHG emissions or climate-related information could result in increased operating costs, impact the demand for the oil and natural gas we produce, and adversely affect our business.

More stringent laws and regulations relating to climate change and GHGs may be adopted 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 monitor, report, and/or reduce GHG emissions from various sources. The 2007 case *Massachusetts v. EPA* held that GHGs are air pollutants covered by the Clean Air Act, and that EPA must determine whether certain GHG emissions may reasonably be anticipated to endanger public health or welfare. In December 2009, EPA issued a final rule stating that current and projected concentrations of carbon dioxide, methane and other GHGs endanger public health and welfare ("2009 Endangerment Finding"). The 2009 Endangerment Finding served as legal support for subsequent EPA Clean Air Act rulemakings that have significantly affected industry operational costs, including New Source Performance Standards and Existing Source Guidelines rules requiring technology investments to detect and reduce methane leaks and emissions from new and existing oil and gas infrastructure. In the 2022 Supreme Court case *West Virginia v. EPA*, the Court held that EPA lacked clear statutory authority under the Clean Air Act, absent specific and explicit authorization from Congress, to implement an EPA rulemaking that mandated a shift for electricity production from higher greenhouse gas emissions sources to lower emissions sources. In the 2024 Supreme Court case *Loper Bright Enterprises v. Raimondo*, the Court held that courts must independently determine the best reading of a statute, rather than deferring to agency interpretations of ambiguous statutory language. On February 12, 2026, EPA issued a pre-publication copy of a final rule, submitted for publication in the Federal Register, rescinding the 2009 Endangerment Finding on the basis that the 2009 Endangerment Finding exceeded EPA authority, was not supported by specific and explicit authorization from Congress, and did not meet the best reading of the underlying Clean Air Act provision under the *West Virginia* and *Loper Bright* holdings. Litigation following the February 2026 final rule publication is expected, and on February 18, 2026, a coalition of environmental and public health groups filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. The potential impact of the February 2026 final rule, potential subsequent revisions to existing emission standards, and the outcome of related litigation, including private nuisance litigation, remain uncertain and could affect our operations. We cannot predict the scope of any future methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility. We cannot predict the scope of any future methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions, such as by means of cap and trade programs. Cap and trade programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In December 2015, the Paris Agreement (an international agreement from the 21st Conference of the Parties ("COP") to the United Nations Framework Convention on Climate Change in Paris, France) resulted in an agreement for signatory countries to nationally determine their contributions and set GHG emission reduction goals. In January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change. The withdrawal became effective in January 2026. In January 2026, President Trump announced the United States will also withdraw from the UN Framework Convention on Climate

Change. At the same time, various state and local governments have committed to furthering the goals of the Paris Agreement.

Any legislation or regulatory programs addressing GHG emissions could increase the cost of consuming, and thereby reduce demand for, the natural gas we produce, and could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements, and to monitor and report on GHG emissions. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Moreover, incentives or requirements to conserve energy, use alternative energy sources, reduce GHG emissions in product supply chains, and increase demand for lower-carbon fuel or zero-operating emissions vehicles, could reduce demand for the oil and natural gas we produce. 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 can 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.

It is not currently possible to predict how these executive orders or any proposed or future GHG or climate change legislation or regulation promulgated by Congress, the states or multi-state regions and their respective regulatory agencies may impact our business. Further, the Supreme Court's decision in *Loper* to overrule *Chevron* 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 such initiatives at the international, state and local levels are expected to continue and any climate change legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business or on the assets we operate could result in increased compliance or operating costs or additional operating restrictions or reduced demand for our products, and could have a material adverse effect on our business, financial condition and results of operations. For further discussion of certain existing and proposed climate-related rules and regulations, see "Business and Properties — Legislative and regulatory environment" included in Items 1 and 2 of Part I of this Annual Report.

Increased scrutiny of ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

Companies across all industries continue to face increased scrutiny from a variety of stakeholders, including investor advocacy groups, proxy advisory firms, certain institutional investors and lenders, investment funds and other influential investors and rating agencies, 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 as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to growing 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. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

Further, our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. We may face pressure from stakeholders, many of whom are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability while at the same time remaining a successfully operating company. At the same time, others may disagree with certain ESG initiatives and recent political developments could subject ESG initiatives and the Company to increased risk of criticism or litigation risks from certain "anti-ESG" parties. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder confidence and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

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 and additional operating restrictions or delays, limit the areas in

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

Hydraulic fracturing is a common practice used to stimulate production of oil and/or natural gas from dense 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 surrounding rock and stimulate production. We and our third-party operators use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies or trigger seismic activity. Proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Local governments 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 or prohibiting the performance of well drilling in general or hydraulic fracturing 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 development activities, and perhaps even be precluded from drilling wells.

In addition, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act (“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. The EPA also finalized rules under the CWA in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Additionally, 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. In March 2016, the U.S. Occupational Safety and Health Administration issued a final rule to impose stricter standards for worker exposure to silica, which went into effect in June 2018 and applies to use of sand as a proppant for hydraulic fracturing. The U.S. Department of the Interior’s Bureau of Land Management (“BLM”) finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. Following years of litigation, the BLM rescinded this rule in December 2017. However, California and various environmental groups filed lawsuits in January 2018 challenging the BLM’s rescission of the rule and, in March 2020, the U.S. District Court for the Northern District of California upheld the BLM’s decision to rescind the rule. However, there is ongoing litigation regarding the BLM rules, and future implementation of these rules is uncertain at this time. In April 2024, the BLM finalized a rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. The final rule took effect in June 2024. However, in May 2024, the states of North Dakota, Texas, Montana, Wyoming, and Utah challenged the rule. In September 2024, the U.S. District Court for the District of North Dakota granted a motion prohibiting the BLM from enforcing the rule against those states pending the outcome of the litigation. 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. The BLM has given notice that it is in the process of considering revisions to the final rule and has delayed enforcement of two provisions included in the April 2024 rule until December 10, 2026. The relevant provisions subject to delayed enforcement imposed measurement device and sampling requirements for flares flowing between 1,050 and 6,000 mcf/month and required operators to submit Leak Detection and Repair plans to the state BLM office; however, the obligation to repair leaks required under the regulations remains in effect. The state litigation against the April 2024 rule has been temporarily suspended pending the BLM’s reconsideration of the April 2024 rule. Accordingly, future implementation and enforcement of this rule is uncertain at this time. New laws or regulations that impose new obligations on, or significantly restrict hydraulic fracturing, could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable and increase our cost of doing business. Such increased costs and any delays or curtailments in our production activities could have a material adverse effect on our business, prospects, financial condition, results of operations and liquidity.

Legislation or regulatory initiatives intended to address the disposal of saltwater gathered from our drilling activities could limit our ability to produce oil and natural gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us 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 gathered 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.

Limitation or restrictions on our ability to obtain or dispose of water may have an adverse effect on our operating results.

Water is an essential component of shale oil and natural gas development during both the drilling and hydraulic fracturing processes. Our access to water to be used in these processes may be adversely affected due to reasons such as periods of extended drought, private, third-party competition for water in localized areas or the implementation of local or state governmental programs to monitor or restrict the beneficial use of water subject to their jurisdiction for hydraulic fracturing to assure adequate local water supplies. In addition, treatment and disposal of water is becoming more highly regulated and restricted. Thus, our costs for obtaining and disposing of water could increase significantly.

In addition, the use, treatment and disposal of water has become a focus of certain investors and other stakeholders who may seek to engage with us on this and other environmental matters, which may result in activism, negative reputational impacts, increased costs or other adverse effects on our business, results of operations and financial condition. Our inability to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact our exploration and production operations and have a corresponding adverse effect on our business, results of operations and financial condition. Furthermore, our operations could be impaired if we are unable to recycle or dispose of the water we produce in an economical and environmentally safe manner.

The effects of climate change may also further exacerbate water scarcity in certain regions, including the areas in which we are active. If distinct weather events or gradual climatic processes were to require us to discontinue or curtail our operations, this could impair ability to economically produce our reserves and would have an adverse effect on our financial condition, results of operations and cash flows.

We are responsible for the decommissioning, abandonment, and reclamation costs for our facilities, which could decrease our cash available for distribution.

We are responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of our facilities at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation. We may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more decommissioning, abandonment and reclamation reserve funds to provide for payment of future decommissioning, abandonment and reclamation costs, which could decrease our cash available for distribution. In addition, such reserves, if established, may not be sufficient to satisfy such future decommissioning, abandonment and reclamation costs and we will be responsible for the payment of the balance of such costs.

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.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife and/or habitats. The Endangered Species Act (“ESA”) and (in some cases) comparable state laws were established to protect endangered and threatened species. 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 natural gas development. In January 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. 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 prior Trump Administration regulations concerning the definition of “habitat” and critical habitat exclusions. In April 2024, the FWS finalized three rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. In August 2024, environmental groups challenged the new ESA regulations in federal district court, which litigation remains ongoing. However, in January 2025, the Trump administration issued an executive order directing (i) agencies to use, to the maximum extent permissible, the ESA regulation on consultations in emergencies, to facilitate the domestic energy supply and (ii) the Endangered Species Act Committee to meet at least quarterly to ensure a prompt and efficient review of all submissions for potential actions that could facilitate energy development. Additionally, in April 2025, the FWS and National Marine Fisheries Service proposed to redefine “harm” to mean affirmative acts that are directed immediately and intentionally against a particular animal, excluding acts or omissions that indirectly cause injury. Additionally, in

November 2025, the Trump Administration proposed several rules that would significantly alter ESA protections for plants and animals. One proposed rule would rescind a rule that automatically extends protections for endangered species to threatened species. Another proposed rule would change regulations for listing species as endangered or threatened as well as for designating critical habitats. Additionally, a third proposed rule would reinstate the framework for evaluating the benefits and cost of designating a critical habitat by considering factors like economic impact, impact on national security, and other relevant impacts. The U.S. Fish and Wildlife Service is expected to issue final rules in 2026. 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, and it is possible the new rules could increase the portion of our lease areas that could be designated as critical habitat. Similar protections are offered to migratory birds under the 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 United States. However, in April 2025, the U.S. Department of Interior issued a memo, M-37085, to repeal M-37065, which had previously declared that the Migratory Bird Treaty Act prohibited both the intentional and incidental "take" of migratory birds. The memo restored M-37050, clarifying that only the intentional "take" of migratory birds is prohibited. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered or further changes to regulations 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.

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

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

Like many oil and gas companies, we are, or may be, from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters, alleged violations of federal or state securities laws and personal injury, environmental damage or property damage matters, in the ordinary course of our business. Additionally, members of our management and our directors may, from time to time, be involved in various legal and other proceedings against the Company naming those officers or directors as co-defendants. 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 and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in 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 and financial condition and affect the value of our common units. 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. The defense of any legal proceedings against us or our officers or directors, could take resources away from our operations and divert management attention. As of the date of this Annual Report, the Company is not aware of any material legal or environmental proceedings contemplated to be brought against the Company or its management.

Loss of our information and computer systems could adversely affect our business. Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

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 natural gas 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.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are subject to a number of privacy and data protection laws, rules and directives (collectively, data protection laws) relating to the processing of personal data.

The regulatory environment surrounding data protection laws is uncertain. Varying jurisdictional requirements could increase the costs and complexity of compliance with such laws, and violations of applicable data protection laws can result in significant penalties. A determination that there have been violations of applicable data protection laws could expose us to significant damage awards, fines and other penalties that could materially harm our business and reputation.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance and adversely affect our business. As noted above, we are also subject to the possibility of security and privacy breaches, which themselves may result in a violation of these laws. Additionally, the acquisition of a company that is not in compliance with applicable data protection laws may result in a violation of these laws.

Risks Inherent in an Investment in Us

Our general partner and its affiliates own a controlling interest in us and have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner has control over all decisions related to our operations. The Sponsor and Tom L. Ward through his ownership of Mach Resources own all of the membership interests in our general partner which are in the same proportion to each other as their limited partner interest ownership in us. The Sponsor and Tom L. Ward through his ownership of Mach Resources also own approximately 74,850,632 and 13,858,781, respectively, of our outstanding common units as of March 5, 2026. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of us and our unitholders, the executive officers and directors of our general partner also have a duty to manage our general partner at the direction of the Sponsor and Tom L. Ward through his ownership of Mach Resources. As a result of these relationships, conflicts of interest may arise in the future between the Sponsor, Tom L. Ward in his capacity as a member of our general partner through his ownership of Mach Resources and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand; provided, however, that under our code of business conduct, any such member of our management, so long as they are an executive officer, is required to avoid personal conflicts of interest and not compete against us, in each case unless approved by the Board. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of us and our common unitholders. These conflicts include, among others, the following:

- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- Neither our partnership agreement nor any other agreement requires the Sponsor (excluding our general partner) to pursue a business strategy that favors us;
- The Sponsor is not limited in its ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;
- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other partnerships with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- Our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 95% of the common units;
- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please read "Certain Relationships and Related Party Transactions and Director Independence" included in Item 13 of Part III of this Annual Report.

Our partnership agreement does not restrict the Sponsor from competing with us. Certain of our directors and officers may in the future spend significant time serving, and may have significant duties with, investment partnerships or other private entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Affiliates of our general partner are not prohibited from owning projects or engaging in businesses that compete directly or indirectly with us. Similarly, our partnership agreement does not limit the Sponsor's ability to compete with us and the Sponsor does not have any obligation to present business opportunities to us.

In addition, certain of our officers and directors may in the future hold similar positions with investment partnerships or other private entities that are in the business of identifying and acquiring mineral and royalty interests. In such capacities, these individuals would likely devote significant time to such other businesses and would be compensated by such other businesses for the services rendered to them. The positions of these directors and officers may give rise to duties that are in conflict with duties owed to us. In addition, these individuals may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may be affiliated. Due to these potential future affiliations, they may have duties to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. The Sponsor will be under no obligation to make any acquisition opportunities available to us.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and holders of our common units.

Our partnership agreement replaces our general partner's fiduciary duties to us and our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with different contractual standards. For example, our partnership agreement provides that:

- whenever our general partner (acting in its capacity as our general partner), the Board or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was not adverse to our best interests, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or equitable principle;
- our general partner may make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners at the time our partnership agreement was entered into where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:
    - how to allocate corporate opportunities among us and its other affiliates;
    - whether to exercise its limited call right;
    - whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board; provided, however, the MSA will require our general partner to seek approval by the conflicts committee of the Board in connection with an amendment to the MSA that, in the reasonable discretion of our general partner, adversely affects our unitholders;
    - how to exercise its voting rights with respect to the units it owns;
    - whether to sell or otherwise dispose of any units or other partnership interests it owns; and
    - whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.
- our general partner will not have any liability to us or our unitholders for breach of any duty in connection with decisions made in its capacity as general partner so long as it acted in good faith (meaning that it subjectively believed that the decision was not adverse to our best interest);
- our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
  - approved by the conflicts committee of the Board, although our general partner is not obligated to seek such approval;
  - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
  - determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
  - determined by the Board to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth sub-bullet points above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow our reserves and production and make acquisitions.

Our partnership agreement provides that we distribute each quarter all of our available cash, which we define as cash on hand at the end of each quarter, less reserves established by our general partner. As a result, we expect to rely primarily upon our cash reserves and external financing sources, including the issuance of additional common units and other partnership securities and borrowings under our New Credit Agreement, to fund future acquisitions and finance our growth. To the extent we are unable to finance growth with our cash reserves and external sources of capital, the requirement in our partnership agreement to distribute all of our available cash may impair our ability to grow.

A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates, prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;
- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil, natural gas and NGLs.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are and will be no limitations in our partnership agreement or the New Credit Agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our business strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. In addition, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions to our unitholders and implied distribution yield. This implied distribution yield is often used by investors to compare and rank similar yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity or incur debt. See "— Increased costs of capital could adversely affect our business."

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to permit the general partner to redeem the units of certain non-citizen unitholders.

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status and/or the nationality, citizenship or other related status of our limited partners (and their owners, to the extent relevant) and to permit our general partner to redeem the units held by any person (i) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (ii) who fails to comply with the procedures established to obtain such proof. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business.

Our unitholders have no right on an annual or ongoing basis to elect our general partner or its board of directors. The Board, including the independent directors, is chosen entirely by the Sponsor and Tom L. Ward through his ownership of Mach Resources, as a result of their ownership of our general partner, and not by our unitholders. Please read "Management of Mach Natural Resources" included in Item 10 of Part III of this Annual Report and "Certain Relationships and Related Party Transactions and Director Independence" included in Item 13 of Part III of this Annual Report. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner has control over all decisions related to our operations. Since affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) collectively own and control the voting of an aggregate of approximately 52.7% of our outstanding common units as of March 5, 2026, the other unitholders do not have an ability to influence any operating decisions and are not able to prevent us from entering into any transactions. However, our partnership agreement can generally be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including common units held by affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources)). Assuming we do not issue any additional common units and affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) do not transfer any of their common units, affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) will generally have the ability to control any amendment to our partnership agreement, including our policy to distribute all of our cash available for distribution to our unitholders. Furthermore, the goals and objectives of the affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) that hold our common units relating to us may not be consistent with those of a majority of the other unitholders. Please read "— Our general partner and its affiliates own a controlling interest in us and have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders."

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

The public unitholders are unable initially to remove our general partner without its consent because affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) own sufficient units to prevent the removal of our general partner. Our general partner may not be removed except by vote of the holders of at least 66⅔% of all outstanding units voting together as a single class is required to remove our general partner. As of March 5, 2026, affiliates of our general partner (including the Sponsor and Tom L. Ward through his ownership of Mach Resources) own approximately 52.7% of our outstanding common units, which enable those holders, collectively, to prevent the removal of our general partner.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the Sponsor or Tom L. Ward through his ownership of Mach Resources which controls our general partner, from transferring all or a portion of their ownership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board and officers of our general partner with their own choices and thereby influence the decisions made by the Board and officers.

We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' limited voting rights by providing that any common units held by a person, entity or group owning 20% or more of any class of common units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such common units with the prior approval of the Board, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our common unitholders to influence the manner or direction of management.

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

As of March 5, 2026, the Sponsor owns 74,850,632 common units, or approximately 44.5% of our limited partner interests, and management owns 14,405,597 common units, or approximately 8.6% of our limited partner interests. Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership interests proposed to be sold by our general partner or any of its affiliates, which includes the Sponsor and Tom L. Ward through his ownership of Mach Resources. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 95% of the then outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercises its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

Our partnership agreement has designated the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders which would limit our unitholders'

ability to choose the judicial forum for disputes with us or our general partner or its directors, officers or other employees.

Our partnership agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court in the State of Delaware with subject matter jurisdiction) will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners, (4) asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. The foregoing provision will not apply to any claims as to which the Court of Chancery determines that there is an indispensable party not subject to the jurisdiction of such court, which is rested in the exclusive jurisdiction of a court or forum other than such court (including claims arising under the Exchange Act), or for which such court does not have subject matter jurisdiction, or to any claims arising under the Securities Act and, unless we consent in writing to the selection of an alternative forum, the United States federal district courts will be the sole and exclusive forum for resolving any action asserting a claim arising under the Securities Act. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules or regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain such Securities Act claims. To prevent having to litigate claims in multiple jurisdictions and the threat of inconsistent or contrary rulings by different courts, among other considerations, the partnership agreement provides that, unless we consent in writing to the selection of an alternative forum, United States federal district courts shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act. There is uncertainty as to whether a court would enforce the forum provision with respect to claims under the federal securities laws. If a court were to find these provisions of our amended and restated agreement of limited partnership 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 business, financial condition or results of operations.

Our partnership agreement also provides that each limited partner waives the right to trial by jury in any such claim, suit, action or proceeding, including any claim under the U.S. federal securities laws, to the fullest extent permitted by applicable law. If a lawsuit is brought against us under our partnership agreement, it may be heard only by a judge or justice of the applicable trial court, which would be conducted according to different civil procedures and may result in different outcomes than a trial by jury would have, including results that could be less favorable to the plaintiffs in any such action. No unitholder can waive compliance with respect to the U.S. federal securities laws and the rules and regulations promulgated thereunder. If the partnership or one of the partnership unitholders opposed a jury trial demand based on the waiver, the applicable court would determine whether the waiver was enforceable based on the facts and circumstances of that case in accordance with applicable state and federal laws. To our knowledge, the enforceability of a contractual pre-dispute jury trial waiver in connection with claims arising under the U.S. federal securities laws has not been finally adjudicated by the United States Supreme Court. However, we believe that a contractual pre-dispute jury trial waiver provision is generally enforceable, including under the laws of the State of Delaware, which govern our partnership agreement. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations, provisions and obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us, our general partner and our general partner’s directors and officers.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf pursuant to the MSA will reduce cash available for distribution to our unitholders. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. The amount and timing of such reimbursements will be determined by our general partner.

We and our general partner have entered into a MSA with Mach Resources pursuant to which Mach Resources will manage and perform all aspects of our oil and gas and midstream operations and other general and administrative functions in exchange for reimbursement of certain expenses. On a monthly basis, we will reimburse our general partner and its affiliates for certain expenses they incur and payments they make on our behalf pursuant to the MSA. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. The reimbursement of expenses to our general partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. For the year ended December 31, 2025, we paid $135.7 million to Mach Resources, which consisted of $7.4 million for a management fee and $128.3 million for reimbursements of its costs and expenses under the management services agreements among Mach Resources, the Company and the Mach Companies.

The NYSE does not require a publicly traded limited partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements. Please read "Management of Mach Natural Resources" included in Item 10 of Part III of this Annual Report.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a Delaware limited partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Our unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make distributions to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If our common unit price declines, our unitholders could lose a significant part of their investment.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in commodity prices;
- changes in securities analysts' recommendations and their estimates of our financial performance;
- public reaction to our press releases, announcements and filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions to our unitholders;
- changes in tax law;

- an election by our general partner to convert or restructure us as a taxable entity;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies, including those relating to auditing standards and disclosure about our executive compensation. Taking advantage of the longer phase-in periods for the adoption of new or revised financial accounting standards applicable to emerging growth companies may make our common units less attractive to investors.

The JOBS Act contains provisions that, among other things, relax certain reporting requirements for "emerging growth companies," including certain requirements relating to auditing standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002, (2) 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, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosure regarding executive compensation required of larger public companies.

We have elected to take advantage of all of the reduced reporting requirements and exemptions available to emerging growth companies under the JOBS Act, including the longer phase-in periods for the adoption of new or revised financial accounting standards under Section 107 of the JOBS Act, until we are no longer an emerging growth company. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable pursuant to Section 107 of the JOBS Act.

Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those of non-emerging growth companies and other emerging growth companies that have opted out of the longer phase-in periods under Section 107 of the JOBS Act and who will comply with new or revised financial accounting standards. We cannot predict if investors will find our common units less attractive because we elected to rely on these exemptions. If some investors find our common units less attractive as a result, there may be a less active trading market for our common units and our common unit price may be more volatile. Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards until such time as those standards apply to private companies.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. We will not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls over financial reporting 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. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent.

Under our partnership agreement, our general partner may, without unitholder approval, cause us to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal income tax purposes, whether by election of the partnership or conversion of the partnership or by any other means or methods. In addition and as part of such determination, affiliates of our general partner may choose to retain their partnership interests in us and cause us to enter into a transaction in which our interests held by other persons are converted into or exchanged for interests in a new entity, taxable as a corporation or subject to entity-level taxation for U.S. federal purposes, whose sole assets are interests in us. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may be material to such unitholder and may vary depending on the unitholder's particular situation and may vary from the tax liability of us or of any affiliates of our general partner who choose to retain their partnership interests in us. Our general partner will have no duty or obligation to make any such determination or take any such actions, however, and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in a manner not adverse to the best interests of us or our limited partners.

We incur increased costs as a result of being a publicly traded partnership.

We have a limited history operating as a publicly traded partnership. As a publicly traded partnership, we incur significant legal, accounting and other expenses that we did not incur prior to the Offering. In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to adopt various corporate governance practices that will further increase our costs. The amount of our expenses or reserves for expenses, including the costs of being a publicly traded partnership will reduce the amount of cash we have for distribution to our unitholders. As a result, the amount of cash we have available for distribution to our unitholders will be affected by the costs associated with being a public company.

We are subject to the public reporting requirements of the Exchange Act. These rules and regulations increase certain of our legal and financial compliance costs and make activities more time-consuming and costly. For example, as a result of becoming a publicly traded company, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting.

We also incur additional expense in order to obtain director and officer liability insurance. Because of the limitations in coverage for directors, it may be more difficult for us to attract and retain qualified persons to serve on the Board or as executive officers than it was prior to the Offering.

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

The trading market for our common units 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 unit price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common units or if our operating results do not meet their expectations, our unit price could decline.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (the "IRS") were to treat us as a corporation for U.S. federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for

U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our classification as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate and we would also likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders could be reduced. Thus, treatment of us as a corporation could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, capital, and other forms of business taxes, as well as subjecting nonresident partners to taxation through the imposition of withholding obligations and composite, combined, group, block, or similar filing obligations on nonresident partners receiving a distributive share of state "sourced" income. We currently own property or do business in Oklahoma, Kansas, Texas, New Mexico and Colorado among other states. Imposition on us of any of these taxes in jurisdictions in which we own assets or conduct business or an increase in the existing tax rates could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships or an investment in our common units, including elimination of partnership tax treatment for certain publicly traded partnerships.

Any changes to U.S. federal income tax laws or interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for U.S. federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. Any such changes to U.S. federal income tax laws or interpretations thereof could adversely impact the value of an investment in our common units.

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

In recent years, legislation has been proposed that would, if enacted, make significant changes to U.S. tax laws, including the reduction or elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. 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 any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the U.S. federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS has made no determination as to our status as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, our costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our unitholders because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. If we bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns (including any income tax returns filed by us or the Mach Companies in respect of periods beginning prior to the closing of the Offering), it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be made or be effective in all circumstances. If we are unable to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our common units during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income, our unitholders may be required to pay U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gains or losses on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder’s allocable share of our net taxable income decrease the unitholder’s tax basis in the unitholder’s common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder’s tax basis in those common units, even if the price received is less than the unitholder’s original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items such as depreciation, depletion, amortization and accretion expense and intangible drilling costs. In addition, because the amount realized may include a unitholder’s share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business (“business interest”) may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investments in our common units by tax-exempt entities, such as individual retirement accounts ("IRAs") or other retirement plans, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. A tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult their tax advisors regarding the impact of these rules on an investment in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our common units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable marginal tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, upon the sale, exchange or other disposition of a common unit by a non-U.S. unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. The U.S. Department of the Treasury and the IRS have issued final regulations providing guidance on the application of these rules for transfers of certain publicly traded partnership interests, including transfers of our common units. Under these regulations, the "amount realized" on a transfer of our common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and such broker will generally be responsible for the relevant withholding obligations. Distributions to non-U.S. unitholders may also be subject to additional withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

We will treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation, depletion, amortization and accretion positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder's tax returns.

Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in Oklahoma, Kansas, Texas, New Mexico and Colorado. Oklahoma, Kansas, New Mexico and Colorado each impose a personal income tax. Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or entity-level income tax. It is the responsibility of each unitholder to file its own U.S. federal, state and local tax returns, as applicable.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult their tax advisors to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

We have adopted and will continue to adopt certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many of the relative fair market value estimates ourselves. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction. A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Mach's cybersecurity posture is proactive and multifaceted, reflecting our prioritization of safeguarding our organization against cyber threats. Through the implementation of advanced technologies and adherence to rigorous standards, we have developed a robust multilayered defense strategy designed to protect our data and information systems and align with industry best practices.

Risk Management and Strategy

Our approach to cybersecurity is comprehensive, and includes continuous risk management strategies to safeguard our digital assets and ensure the integrity and confidentiality of our data.

We employ a strategic combination of the National Institute of Standards and Technology (NIST) Cybersecurity Framework, the International Organization for Standardization (ISO), and the Center for Internet Security (CIS) best practice standards to benchmark and enhance our cybersecurity measures. We believe this multifaceted approach allows us to maintain a robust security posture, manage risks, and respond to evolving cyber threats.

Our cybersecurity practices include:

- Data Monitoring and Loss Prevention: We continuously scan and monitor our systems to detect and prevent data breaches, in an effort to ensure sensitive information remains secure.

- Network Vulnerability Testing: Regular assessments of our network's security through certified third-party testers to identify and remediate vulnerabilities.

- Robust Encryption: Implement strong encryption protocols to protect data in transit and at rest, mitigating the risk of unauthorized access.

- Continuous Monitoring: We are monitoring our digital environment continuously to detect and respond to potential security incidents quickly.

- Regular Updates: Systematic updates to our security systems in response to new threats and vulnerabilities, in an effort to maintain effective defenses.

In addition to assessing our own cybersecurity preparedness, we also consider and evaluate cybersecurity risks associated with use of third-party service providers. We obtain Systems and Organization Controls (“SOC”) 1 and SOC 2 reports, as applicable, from our third-party service providers which assess those entities’ controls to cover security, availability, integrity, confidentiality and privacy. Any applicable findings of this third-party assessment are analyzed by the appropriate employees and further action is taken as needed.

Management

Cybersecurity is a paramount enterprise risk, demanding vigilant attention and strategic planning. Our Chief Information Officer (“CIO”), with over 20 years of technological and leadership experience in the oil and gas industry, is responsible for all aspects of the Company’s information technology, including cybersecurity, networking, infrastructure, applications, data management and protection. The Cybersecurity Team led by the CIO, assesses and manages cybersecurity threats, implements the comprehensive cybersecurity risk management program, and supervises both the internal IT staff and external cybersecurity consultants.

The Cybersecurity Team serves a crucial role in reporting significant incidents to the CIO. The Cybersecurity Team, along with our CIO, convenes at least once each week to review any incidents related to digital security and the corresponding response actions, analyze emerging threats to the organization’s cybersecurity landscape, and deliberate on and discuss preventative strategies. Our Cybersecurity Team receives cybersecurity news and updates from various private energy sector and federal security working groups and organizations.

Governance

Cybersecurity risks are managed alongside the Company’s other enterprise risks, which the Board of Directors oversees. The Company’s IT security efforts, encompassing cybersecurity, fall under the oversight of the Audit Committee of the Board of Directors. The Company’s cybersecurity strategy undergoes a quarterly review by the Audit Committee. During these sessions, the CIO provides a comprehensive update to the Audit Committee on cybersecurity and data protection matters. This includes an assessment of the Company’s actions to recognize and reduce cybersecurity risks. Furthermore, the Company adheres to established procedures for reporting significant cybersecurity events to the Audit Committee or the Board, as appropriate.

To date, the Company has not experienced any material cybersecurity incidents, and we are not aware of any cybersecurity risks that are reasonably likely to materially affect our business strategy, results or financial condition. Please see “Risk Factors” in Item 1A in this Annual Report on Form 10-K for further discussion regarding the Company’s cybersecurity risks.

Item 3. Legal Proceedings

The Company may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business including, but not limited to, title disputes, royalty disputes, contract claims, personal injury claims and employment claims. See Note 10 in “Item 8. Financial Statements and Supplementary Data” of this Annual Report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

The Company, as an owner and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution cleanup resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage that is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company is not aware of any environmental claims existing as of December 31, 2025. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered on the Company’s oil and gas properties.

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

Our common units are listed and traded on the NYSE under the ticker symbol "MNR." As of March 5, 2026, there were 168,218,770 common units outstanding held by 8 holders of record. Because many of our common units are held by brokers and other institutions on behalf of unitholders, we are unable to estimate the total number of unitholders represented by these holders of record.

Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash each quarter. Our cash distribution policy reflects a basic judgment that our unitholders generally will be better served by us distributing our available cash, after costs, expenses and reserves, rather than retaining it. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions from our available cash in the aforementioned or any other amount, and our general partner has considerable discretion to determine the amount of cash available for distribution each quarter.

Because our policy will be to distribute all available cash we generate each quarter, without reserving cash for future distributions or borrowing to pay distributions during periods of low revenue, our unitholders will have direct exposure to fluctuations in the amount of cash generated by our business. Our quarterly cash distributions from our available cash, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in the performance of our operators and revenue caused by fluctuations in the prices of oil and natural gas. Such variations may be significant.

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

less, the amount of cash reserves established by our general partner to:

• provide for the proper conduct of our business, which will include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

• comply with applicable law, any of our debt instruments or other agreements; or

• provide funds for distributions to our unitholders for any one or more of the next four quarters;

plus, all cash and cash equivalents on hand on the date of determination resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter;

plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination resulting from working capital borrowings made after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Unregistered Sale of Equity Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Item 6. [Reserved]
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial *condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. The following discussion and analysis should be read in conjunction with the historical audited consolidated financial statements and related notes included in Item 8 of Part II of this Annual Report and also with "Risk Factors" included in Item 1A of Part I of this Annual Report. We have applied provisions of the SEC's FAST Act Modernization and Simplification of Regulation S-K, which limits the discussion to the two most recent fiscal years. The following information updates the discussion of our financial condition provided in our previous filings, and analyzes the changes in the results of operations between the years ended December 31, 2025 and 2024.*

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance, which may affect our future operating results and financial position. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Actual results and the timing of the events 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, market prices for oil, natural gas and NGLs, net production volumes, estimates of proved reserves, capital expenditures, economic, inflationary and competitive conditions, drilling results, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly under "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements," 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 an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas; the San Juan Basin region of New Mexico and Colorado; and the Permian Basin region of West Texas, and we operate approximately 12,000 PDP wells.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Woodford and Mississippian, Mancos and Fruitland formations. Our experience across these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments. We also own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. Our midstream assets enhance the value of our properties by allowing us to optimize pricing, increase flow assurance and eliminate third-party costs and inefficiencies. In addition, our owned midstream systems generate third-party revenue.

Market Outlook

Our financial results depend on many factors, particularly commodity prices and our ability to find, develop and market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand. The oil and natural gas industry is cyclical and commodity prices are highly volatile and we expect continued and increased pricing volatility in the crude oil and natural gas markets. Regional and worldwide economic activity, including any economic downturn or recession that has occurred or may occur in the future, extreme weather conditions and other substantially variable factors, influence market conditions for these products. Between January 1, 2024 and December 31, 2025, NYMEX WTI prices for crude oil ranged from $55.27 to $86.91 per Bbl, and the NYMEX Henry Hub price of natural gas ranged from $1.58 to $5.29 per MMbtu. The war in Ukraine and conflict in the Middle East and South America, uncertainty regarding interest rates, global supply chain disruptions, tariff volatility, OPEC+'s decision to increase production in May and July 2025, concerns about a potential economic downturn or recession, and instability in the financial sector have contributed to recent economic and pricing volatility and may continue to impact pricing throughout 2026.

Between 2022 and 2024, the Federal Reserve raised the target range for the federal funds rate in an effort to curb inflation. In September 2025, October 2025 and December 2025 the Federal Reserve lowered the target range for the federal funds rate to its current range of 3.50% to 3.75% in light of the reduced inflation. In December 2025, inflation, as measured by the consumer price index, was 2.7%. We cannot predict the future inflation rate but to the extent we experience high inflation, we may see cost increases in our operations, including costs for drill rigs, workover rigs, tubulars and other well equipment, as well as increased labor costs. We continue to evaluate actions to mitigate supply chain and inflationary pressures and work closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical supplies which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient. Further, if we are unable to recover higher costs through higher commodity prices, our current revenue stream, estimates of future reserves, borrowing base calculations, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions would all be significantly impacted.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including the following sources of our revenue, principal components of our cost structure and other financial metrics:

- net production volumes;
- realized prices on the sale of oil, natural gas and NGLs;
- lease operating expense;
- Adjusted EBITDA; and
- cash available for distribution.

Factors Affecting the Comparability of Our Future Results of Operations to Our Historical Results of Operations

Our future results of operations may not be comparable to our historical results of operations for the periods presented, primarily for the reasons described below.

Acquisitions

We have completed six acquisitions in the last two years, most notably the IKAV and Sabinal Acquisitions (as defined in Note 3) that closed in September 2025. These acquisitions are reflected in our results of operations as of and after the date of completion for each such acquisition. As a result, periods prior to each such acquisition will not contain the results of such acquired assets which will affect the comparability of our results of operations for certain historical periods. We may continue to grow our operations through acquisitions when economical, including by funding such acquisitions under our New Credit Agreement.

Results of Operations

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

Revenue

The following table provides the components of our revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	Year Ended December 31,		Change	
($ in thousands)	**2025**	**2024**	**Amount**	**Percent**
Revenues:				
Oil	$ 491,837	$ 555,692	$ (63,855)	(11%)
Natural gas	373,134	195,472	177,662	91%
Natural gas liquids	172,679	185,621	(12,942)	(7%)
Total oil, natural gas, and NGL sales	1,037,650	936,785	100,865	11%
Gain (loss) on oil and natural gas derivatives, net	81,289	(18,854)	100,143	NM[(1)]
Midstream revenue	27,561	24,341	3,220	13%
Product sales	28,890	27,356	1,534	6%
Total revenues	$ 1,175,390	$ 969,628	$ 205,762	21%
Average Sales Price:				
Oil ($/Bbl)	$ 63.72	$ 75.27	$ (11.55)	(15%)
Natural gas ($/Mcf)	$ 2.76	$ 1.93	$ 0.83	43%
NGL ($/Bbl)	$ 23.00	$ 24.79	$ (1.79)	(7%)
Total ($/Boe) – before effects of realized derivatives	$ 27.46	$ 29.52	$ (2.06)	(7%)
Total ($/Boe) – after effects of realized derivatives	$ 28.76	$ 30.07	$ (1.31)	(4%)
Net Production Volumes:				
Oil (MBbl)	7,719	7,382	337	5%
Natural gas (MMcf)	135,026	101,147	33,879	33%
NGL (MBbl)	7,507	7,489	18	0%
Total (MBoe)	37,731	31,729	6,002	19%
Average daily total volumes (MBoe/d)	103.37	86.69	16.68	19%

[(1)]Not Meaningful

Revenue and Other Operating Income

Oil, natural gas and NGL sales

Revenues from oil, natural gas and NGL sales increased $100.9 million, or 11%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. This increase was primarily related to a 19% production increase, which resulted in increased oil, natural gas and NGL sales of $115.5 million. These increases were slightly offset with an overall decrease in the average selling price of our products, which resulted in a decrease in oil, natural gas, and NGL sales of $14.6 million.

Oil, natural gas and NGL production

Production increased 6,002 MBoe, or 19%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. The increase was primarily a result of acquisitions that closed during 2025 which added approximately 8,271 MBoe, offset by natural declines on existing wells.

Oil and natural gas derivatives

For the year ended December 31, 2025, we had realized gains on derivative instruments of $49.2 million and unrealized gains of $32.1 million for total gains of $81.3 million. For the year ended December 31, 2024, we had realized gains on derivative instruments of $17.5 million and unrealized losses of $36.3 million for total losses of $18.9 million. The increase in realized gains is primarily from the overall decrease in oil prices throughout 2025, as well as $13.8 million in early settlements from unwinding a portion of our natural gas derivatives in 2025.

Midstream revenue

Midstream revenue increased $3.2 million, or 13%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024, primarily due to the acquisition of additional midstream facilities in the IKAV Acquisition in September 2025.

Product sales

Product sales increased $1.5 million, or 6%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. This increase was primarily a result of the increase in the average selling price of natural gas. These increases corresponded with the increase in our cost of product sales noted below.

Operating Expenses

The following table summarizes our expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	Year Ended December 31,		Change	
($ in thousands)	**2025**	**2024**	**Amount**	**Percent**
Operating Expenses:				
Gathering and processing expense	$ 138,836	$ 106,152	$ 32,684	31%
Lease operating expense	263,793	180,513	83,280	46%
Production taxes	48,761	45,674	3,087	7%
Midstream operating expense	13,319	10,466	2,853	27%
Cost of product sales	25,901	24,026	1,875	8%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	280,459	261,949	18,510	7%
Depreciation and amortization expense – other	12,305	9,018	3,287	36%
General and administrative	56,636	40,838	15,798	39%
Impairment of oil and gas properties	90,430	—	90,430	100%
Total operating expenses	$ 930,440	$ 678,636	$ 251,804	37%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 3.68	$ 3.35	$ 0.33	10%
Lease operating expense	$ 6.99	$ 5.69	$ 1.30	23%
Production taxes (% of oil, natural gas and NGL sales)	4.7%	4.9%	(0.2%)	(4%)
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 7.43	$ 8.26	$ (0.83)	(10%)
Depreciation and amortization expense – other	$ 0.33	$ 0.28	$ 0.05	18%
General and administrative	$ 1.50	$ 1.29	$ 0.21	16%

Gathering and processing expense

Gathering and processing expense increased by $32.7 million, or 31%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024, primarily as a result of higher fuel costs due to higher natural gas prices, the IKAV Acquisition which added $13.9 million of expenses, and changes in certain purchaser contracts in the second quarter of 2025, which resulted in certain post-production costs that were previously presented as a reduction to gas revenue are now presented as gathering and processing expense.

Lease operating expense

Lease operating expense increased $83.3 million, or 46%,for the year ended December 31, 2025, as compared to the year ended December 31, 2024, primarily as a result of acquisitions in the fourth quarter of 2024 and throughout 2025, which increased lease operating expenses by $76.1 million. Lease operating expenses per Boe increased by $1.30, primarily as a result of the oil-heavy production from the Sabinal Acquisition that added to our overall cost profile.

Production taxes

Production taxes increased $3.1 million, or 7%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. This increase was primarily a result of increased production which resulted in additional production taxes of $3.5 million, partially offset with a decrease in pricing. Production taxes as a percentage of oil, natural gas and NGL sales were consistent from year to year.

Midstream operating expense

Midstream operating expense increased $2.9 million, or 27%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. The increase in midstream operating expense is primarily related to increases from acquisitions of $1.2 million, increases of produced water operating expense of $1.1 million, and increases to gathering operating expense of $1.3 million. These increases were offset with a decrease to plant operating expense of $0.7 million, driven by lower ad valorem taxes in 2025.

Cost of product sales

Cost of product sales increased $1.9 million, or 8%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. This increase was primarily a result of the increase in the average selling price of natural gas. These increases were consistent with the increase in product sales noted above.

Depreciation, depletion, amortization and accretion expense

Depreciation, depletion, amortization and accretion expense for oil and natural gas properties increased by $18.5 million, or 7%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. The increase is primarily a result of acquisitions that closed during 2025.

General and administrative costs

General and administrative costs increased $15.8 million, or 39%, for the year ended December 31, 2025, as compared to the year ended December 31, 2024. The increase in general and administrative costs was primarily acquisition transaction expenses of $17.8 million included in general and administrative expense for the year ended December 31, 2025.

Impairment of oil and gas properties

Impairment of oil and gas properties increased $90.4 million for the year ended December 31, 2025, as compared to the year ended December 31, 2024, as a result of the full cost ceiling test during the third quarter of 2025.

Liquidity and Capital Resources

Our primary sources of liquidity and capital are cash flows generated by operating activities, borrowings under the New Credit Agreement, and proceeds from the issuance of equity and debt. At December 31, 2025, outstanding borrowings under the New Credit Agreement were $1.15 billion with $5.0 million in letters of credit outstanding, and the remaining availability under the New Credit Agreement was $295.0 million at December 31, 2025.

We may need to utilize the public equity or debt markets and bank financings to fund future acquisitions or capital expenditures, but the price at which our common units will trade could be diminished as a result of the limited voting rights of unitholders. We expect to be able to issue additional equity and debt securities from time to time as market conditions allow to facilitate future acquisitions. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations or to refinance our indebtedness will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory, weather and other factors.

Our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner, which we refer to as “available cash.” Our quarterly cash distributions may vary from quarter to quarter as a direct result of variations in the performance of our business, including those caused by fluctuations in commodity prices. Any such variations may be significant, and as a result, we may pay limited or even no cash distributions to our unitholders.

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. We spent approximately $251.9 million in 2025 on development costs and our budget for 2026 is between $315.0 million and $360.0 million. For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2026 is anticipated to focus on a mix of drilling Mississippian and Mancos wells.

During the year ended December 31, 2025, we spent approximately $205.1 million on drilling and completion activities and related equipment and spud 27.1 net wells while bringing online 34.1 net wells, $38.5 million on remedial workovers and other capital projects, $8.3 million on midstream and other property and equipment capital projects and $1.3 billion on acquisitions.

Our 2026 capital expenditures program is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, including acid to be used for our acid stimulation completion, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows and reduce our cash available for distribution to unitholders.

Based on current oil and natural gas price expectations, we believe that our cash flow from operations, together with borrowings from time to time under the New Credit Agreement, will be sufficient to fund our operations through 2026 and the foreseeable future. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. For example, we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled on drilling locations not classified as proved reserves in our December 31, 2025 reserve report. The failure to achieve anticipated production and cash flow from operations from such wells could result in a reduction in future capital spending and/or our ability to pay distributions to unitholders. We cannot assure you that operations and other needed capital will be available on acceptable terms or at all.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Year ended December 31,	
(in thousands)	**2025**	**2024**
Net cash provided by operating activities	$ 506,956	$ 505,292
Net cash (used in) investing activities	(899,162)	(306,316)
Net cash provided by (used in) financing activities	329,063	(245,992)

Net cash provided by operating activities.

Net cash provided by operating activities increased $1.7 million for the year ended December 31, 2025, as compared to the year ended December 31, 2024.

Net cash (used in) investing activities.

Net cash (used in) investing activities increased $592.8 million for the year ended December 31, 2025, as compared to the year ended December 31, 2024. The increase in net cash used in investing activities is primarily attributable to an increase in cash used in acquisitions of $507.3 million as well as an increase in capital expenditures on our oil and gas properties of $52.9 million from 2025 to 2024.

Net cash provided (used in) by financing activities.

Net cash provided by (used in) by financing activities increased $575.1 million for the year ended December 31, 2025, as compared to the year ended December 31, 2024. The increase in cash provided by borrowings under our New Credit Agreement and Revolving Credit Agreement, net of repayments of $448.8 million, and an increase in cash provided from proceeds from equity offerings of $92.2 million. Additionally, there was a decrease of distributions paid to unitholders of $65.3 million. These were partially offset by increases in new debt issuance costs of $23.5 million and prepayment penalties of $7.7 million.

Debt Agreements

New Credit Agreement

On February 27, 2025, the Company entered into the New Credit Agreement, among the Company, the lenders and issuing banks party thereto from time to time and Truist Bank, as the administrative agent and collateral agent.

The New Credit Agreement has (i) an initial borrowing base and elected commitment amount of $750.0 million, with a maximum commitment amount of $2.0 billion subject to borrowing base availability, (ii) a maturity date of February 27, 2029 and (iii) an interest rate equal to, at the Company's election, (a) term SOFR (subject to a 0.10% per annum adjustment) plus a margin ranging from 3.00-4.00% per annum or (b) a base rate plus a margin ranging from 2.00-3.00%

per annum, with the margin dependent upon borrowing base utilization at the time of determination. The Company is also required to pay a commitment fee of 0.50% per annum on the daily unused portion of the current aggregate commitments under the New Credit Agreement.

The New Credit Agreement's borrowing base is redetermined semi-annually, in April and October. The New Credit Agreement requires the Company to maintain as of the last day of each fiscal quarter (i) a consolidated total net leverage ratio of less than or equal to 3.00 to 1.00 and (ii) a current ratio of no less than 1.00 to 1.00.

The Company used borrowings from the New Credit Agreement, together with cash on hand and proceeds from the February 2025 Offering (as defined below), to repay the Term Loan Credit Agreement and the Revolving Credit Agreement (as defined below) in full.

On September 12, 2025, the Company entered into the First Amendment. The First Amendment, among other things, (a) removes the 0.10% per annum credit spread adjustment otherwise applicable to the determination of Term SOFR (as defined in the New Credit Agreement), (b) excludes up to $750.0 million in principal amount of Borrowing Base Reduction Debt (as defined in the New Credit Agreement) issued prior to December 31, 2025 from the provisions otherwise requiring a borrowing base reduction as a result of the issuance of such indebtedness and (c) provides for (i) a $700.0 million aggregate increase in the borrowing base under the Credit Agreement and (ii) the establishment of aggregate term loan commitments (prior to giving effect to any prior funding of term loans) in an amount of $450.0 million and the funding of any unfunded term loan commitments thereunder and increase the Aggregate Elected Revolving Commitment Amount (as defined in the Credit Agreement) to $1.0 billion.

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.

Contractual Obligations and Commitments

We are a party to firm transportation contracts for the transport of natural gas. We incurred approximately $0.4 million in firm transportation contracts for the year ended December 31, 2025. For further information on firm transportation contracts, see Note 10 of our consolidated financial statements.

As part of the IKAV Acquisition, we are now party to a firm sales contract to deliver and sell a certain amount of natural gas at a fixed price of $1.72 per MMbtu through 2030. We expect to fulfill the delivery commitments primarily with production from proved developed reserves. Our production has been sufficient to satisfy the delivery commitments during the periods presented, and we expect our future production will continue to be the primary means of fulfilling the future commitments. However, if our production is not sufficient to satisfy the delivery commitments, we can and may use spot market purchases to satisfy the commitments. For further information on firm sales commitments, see Note 10 of our consolidated financial statements.

Operating lease obligations

Our operating lease obligations include long-term lease payments for office space, vehicles, and equipment related to exploration, development and production activities. We paid approximately $8.3 million in operating lease payments for the year ended December 31, 2025 and expect to pay approximately $22.1 million in operating lease payments through 2030. For further information on our operating lease obligations, see Note 11 of our consolidated financial statements.

Non-GAAP Financial Measures

Adjusted EBITDA

We include in this Annual Report the supplemental non-GAAP financial performance measure Adjusted EBITDA and provide our calculation of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income, our most directly comparable financial measure calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income before (1) interest expense, net, (2) depreciation, depletion, amortization and accretion, (3) unrealized (gain) loss on derivative instruments, (4) impairment on oil and gas assets, (5) loss on debt extinguishment, (6) equity-based compensation expense and (7) gain on sale of assets, net.

Adjusted EBITDA is used as a supplemental financial performance measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to more effectively evaluate our operating performance and our results of operation from period to period and against our peers without regard to financing methods, capital structure or historical cost basis. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA is not a measurement of our financial performance under GAAP and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as indicators of our operating performance. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDA. Our presentation of Adjusted EBITDA should not be construed as an inference that our results will be unaffected by unusual items. Our computations of Adjusted EBITDA may not be identical to other similarly titled measures of other companies.

Cash Available for Distribution

Cash available for distribution is not a measure of net income or net cash flow provided by or used in operating activities as determined by GAAP. Cash available for distribution is a supplemental non-GAAP financial performance measure used by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess our ability to internally fund our exploration and development activities, pay distributions, and to service or incur additional debt. We define cash available for distribution as net income adjusted for (1) interest expense, net, (2) depreciation, depletion, amortization and accretion, (3) unrealized (gain) loss on derivative instruments, (4) impairment on oil and gas assets, (5) loss on debt extinguishment, (6) equity-based compensation expense, (7) gain on sale of assets, (8) cash interest expense, net, (9) development costs and (10) change in accrued realized derivative settlements. Development costs include all of our capital expenditures, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances. Cash available for distribution is not a measurement of our financial performance or liquidity under GAAP and should not be considered as an alternative to, or more meaningful than, net income or net cash provided by or used in operating activities as determined in accordance with GAAP or as indicators of our financial performance and liquidity. The GAAP measure most directly comparable to cash available for distribution is net income. Cash available for distribution should not be considered as an alternative to, or more meaningful than, net income.

Reconciliations of GAAP Financial Measures to Adjusted EBITDA and Cash Available for Distribution

The following table presents our reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measures Adjusted EBITDA and cash available for distribution, as applicable, for each of the periods indicated.

	Year Ended December 31,	
(in thousands)	2025	2024
Net Income Reconciliation to Adjusted EBITDA:		
Net income	$ 142,984	$ 185,179
Interest expense, net	71,555	100,179
Depreciation, depletion, amortization and accretion	292,764	270,967
Unrealized (gain) loss on derivative investments	(32,109)	36,311
Impairment of oil and gas properties	90,430	—
Loss on debt extinguishment	18,540	—
Equity-based compensation expense	9,390	6,531
Gain on sale of assets	(298)	(686)
Adjusted EBITDA	$ 593,256	$ 598,481
Net Income Reconciliation to Cash Available for Distribution:		
Net income	$ 142,984	$ 185,179
Interest expense, net	71,555	100,179
Depreciation, depletion, amortization and accretion	292,764	270,967
Unrealized (gain) loss on derivative investments	(32,109)	36,311
Impairment of oil and gas properties	90,430	—
Loss on debt extinguishment	18,540	—
Equity-based compensation expense	9,390	6,531
Gain on sale of assets	(298)	(686)
Cash interest expense, net	(66,405)	(92,789)
Development costs	(251,854)	(239,435)
Change in accrued realized derivative settlements	(604)	(150)
Cash Available for Distribution	$ 274,393	$ 266,107

Reconciliation of PV-10 to Standardized Measure

Certain of our oil and natural gas reserve disclosures included in this Annual Report are presented on a PV-10 basis. 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 of discounted future net cash flows from production of proved oil and natural gas reserves (the “Standardized Measure”), 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. The Company is a limited partnership treated as a partnership for federal and state income tax purposes, and accordingly is not subject to entity level taxation. However, the Company does pay franchise taxes in the state of Texas, which are represented as income taxes in the calculation of the Company’s Standardized Measure in Note 17 in our financial statements.

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.

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions we consider to be most significant to our financial statements are discussed below.

Oil and Natural Gas Accounting and Reserves

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

Estimates of natural gas and oil reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in oil, natural gas, or NGL prices could result in actual results differing significantly from our estimates. Revisions of previous reserve estimates accounted for approximately $209.4 million, or 18% of the change in the standardized measure of our total reserves from December 31, 2024 to December 31, 2025. For the year ended December 31, 2025, we recorded a full cost ceiling test impairment of $90.4 million. Given the decline of oil prices through 2025, we may have additional ceiling test impairments of our oil and natural gas properties in subsequent quarters if the 12-month average trailing price does not improve. Any such ceiling test impairment could be material to our net earnings; however, given the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to estimate the potential changes in these estimates and their impact on the impairment. See Note 17 of our consolidated financial statements for further information.

Business Combinations

We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 — Business Combinations, and involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based on the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values.

The most significant assumptions relate to the estimated fair values assigned to our proved oil and natural gas properties. The assumptions made in performing these valuations include future net production volumes, future commodity prices and costs, future operating and development activities, projections of oil and gas reserves and a weighted average cost of capital rate. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings. See Note 3 of our consolidated financial statements for further discussion of business combinations.

Recently Issued Accounting Pronouncements

A summary of recent accounting pronouncements and our assessment of any expected impact of these pronouncements, if known, is included in Note 2 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Oil and gas revenue

Our revenue and cash flow 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 natural gas properties.

Commodity derivative activities

To reduce the impact of fluctuations of commodity prices on our total revenue and other operating income, we have historically used, and we expect to continue to use, commodity derivative instruments, primarily swaps, to hedge price risk associated with a portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in prices and may partially limit our potential gains from future increases in prices. We do not enter derivative contracts for speculative trading purposes. The New Credit Agreement contains various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

Our hedging activities are intended to support oil and natural gas prices at targeted levels and manage our exposure to natural gas price volatility. Under swap contracts, the counterparty is required to make a payment to us for the difference between the swap price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the swap price. We are required to make a payment to the counterparty for the difference between the swap price and the settlement price if the swap price is below the settlement price. See Note 7 of the notes to our consolidated financial statements included in Item 8 of Part II of this Annual Report for further information on our open derivative positions.

Counterparty and Customer Credit Risk

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of a contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. As of December 31, 2025, we had derivative instruments in place with 9 different counterparties. We believe our counterparties currently represent acceptable credit risks. We are not required to provide credit support or collateral to our counterparties under current contracts, nor are they required to provide credit support or collateral to us.

Substantially all of our revenue and receivables result from oil and gas sales to third parties operating in the oil and gas industry. Our receivables also include amounts owed by joint interest owners in the properties we operate. Both our purchasers and joint interest partners have recently experienced the impact of significant commodity price volatility as discussed above under “— Commodity Price Risk — Oil and Gas Revenue.” This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in commodity prices and economic and other conditions. In the case of joint interest owners, we often have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings.

Interest Rate Risk

Variable rate debt

At December 31, 2025, we had $1.15 billion of debt outstanding under the New Credit Agreement. Borrowings outstanding under the New Credit Agreement bore an interest rate of 7.7% as of December 31, 2025. Assuming no change in the amount outstanding, the impact on interest expense of a 1% (or 100 basis points) increase or decrease in the assumed weighted average interest rate on our variable interest debt would be approximately $11.5 million per year based on our borrowings outstanding at December 31, 2025.

Interest rate derivative activities

As of December 31, 2025, we did not have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness, but we may enter into such derivative arrangements in the future. To the extent we enter into any such interest rate derivative arrangement, we would be subject to risk for financial loss.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS
MACH NATURAL RESOURCES LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders
Mach Natural Resources LP

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Mach Natural Resources LP (a Delaware limited partnership) and subsidiaries (the “Company”) as of December 31, 2025 and 2024, the related consolidated statements of operations, partners’ capital and 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 “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the 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/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma
March 12, 2026

MACH NATURAL RESOURCES LP
CONSOLIDATED BALANCE SHEETS
(in thousands)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 42,633	$ 105,776
Accounts receivable – joint interest and other, net	70,167	38,606
Accounts receivable – oil, gas, and NGL sales	160,249	132,945
Short-term derivative assets	42,506	14,069
Inventories	43,511	24,301
Other current assets	18,886	6,399
Total current assets	377,952	322,096
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	4,017,896	2,419,998
Less: accumulated depreciation, depletion, amortization and impairment	(879,253)	(520,641)
Oil and natural gas properties, net	3,138,643	1,899,357
Other property, plant and equipment	230,265	115,475
Less: accumulated depreciation	(35,511)	(23,710)
Other property, plant and equipment, net	194,754	91,765
Long-term derivative assets	12,492	640
Other assets	34,001	9,487
Operating lease assets	19,466	14,869
Total assets	$ 3,777,308	$ 2,338,214
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 68,706	$ 52,440
Accounts payable – related party	915	1,996
Accrued liabilities	115,565	52,920
Revenue payable	167,829	150,745
Short-term derivative liabilities	—	6,233
Current portion of long-term debt	—	82,500
Current portion of operating lease liabilities	6,906	5,587
Total current liabilities	359,921	352,421
Long-term debt	1,144,056	668,778
Asset retirement obligations	261,856	101,858
Long-term derivative liabilities	2,962	4,873
Long-term portion of operating leases	12,645	9,302
Other long-term liabilities	6,479	1,936
Total long-term liabilities	1,427,998	786,747
Commitments and contingencies (Note 10)		
Partners' capital:		
Partners' capital	1,989,389	1,199,046
Total liabilities and partners' capital	$ 3,777,308	$ 2,338,214

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

MACH NATURAL RESOURCES LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per common unit data)

	Year Ended December 31,		
	2025	2024	2023
Revenue			
Oil, natural gas, and NGL sales	$ 1,037,650	$ 936,785	$ 647,352
Gain (loss) on oil and natural gas derivatives	81,289	(18,854)	57,272
Midstream revenue	27,561	24,341	26,328
Product sales	28,890	27,356	31,357
Total revenues	1,175,390	969,628	762,309
Operating expenses			
Gathering and processing	138,836	106,152	39,449
Lease operating expense	263,793	180,513	127,602
Production taxes	48,761	45,674	31,882
Midstream operating expense	13,319	10,466	10,873
Cost of product sales	25,901	24,026	28,089
Depreciation, depletion, amortization and accretion – oil and natural gas	280,459	261,949	131,145
Depreciation and amortization – other	12,305	9,018	6,472
General and administrative	49,236	33,438	22,861
General and administrative – related party	7,400	7,400	4,792
Impairment of oil and gas properties	90,430	—	—
Total operating expenses	930,440	678,636	403,165
Income from operations	244,950	290,992	359,144
Other (expense) income			
Interest expense	(72,219)	(104,596)	(11,201)
Loss on debt extinguishment	(18,540)	—	—
Other (expense) income, net	(11,207)	(1,217)	(1,385)
Total other expense	(101,966)	(105,813)	(12,586)
Net income	$ 142,984	$ 185,179	$ 346,558
Less: net income attributable to Predecessor	—	—	(278,040)
Net income attributable to Mach Natural Resources LP	$ 142,984	$ 185,179	$ 68,518
Net income per common unit attributable to Mach Natural Resources LP			
Basic	$ 1.09	$ 1.90	$ 0.72
Diluted	$ 1.09	$ 1.90	$ 0.72
Weighted average common units outstanding:			
Basic	131,455	97,591	94,907
Diluted	131,537	97,701	94,907

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

MACH NATURAL RESOURCES LP
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL AND MEMBERS' EQUITY
(in thousands)

	Predecessor	Mach Natural Resources LP		
	Members' Equity	Common Units	Partners' Capital	Total Partners' Capital and Members' Equity
Balance at December 31, 2022	$ 593,230	—	$ —	$ 593,230
Contributions	20,000	—	—	20,000
Distributions	(101,350)	—	—	(101,350)
Equity compensation	2,595	—	—	2,595
Net income prior to the Corporate Reorganization	278,040	—	—	278,040
Common units issued in Corporate Reorganization to Existing Owners of BCE-Mach III LLC (Note 1)	(792,515)	76,769	792,515	—
Common units issued for the acquisitions of BCE-Mach I LLC and BCE-Mach II LLC (Note 3)	—	11,981	227,644	227,644
Common units issued in the Offering, net of underwriting fees and offering expenses (Note 1)	—	10,000	168,465	168,465
Common units repurchased from Exchanging Members (Note 1)	—	(3,750)	(66,263)	(66,263)
Equity compensation subsequent to the Corporate Reorganization	—	—	845	845
Net income subsequent to the Corporate Reorganization	—	—	68,518	68,518
Balance at December 31, 2023	$ —	95,000	$ 1,191,724	$ 1,191,724
Net income	—	—	185,179	185,179
Distributions to unitholders	—	—	(311,622)	(311,622)
Equity compensation	—	—	6,531	6,531
Vesting of phantom units, net of units withheld for withholding taxes	—	199	(1,618)	(1,618)
Common units issued in the public offering, net of underwriting fees and offering expenses	—	8,291	128,852	128,852
Balance at December 31, 2024	$ —	103,490	$ 1,199,046	$ 1,199,046
Net income	—	—	142,984	142,984
Distributions to unitholders	—	—	(245,268)	(245,268)
Equity compensation	—	—	9,390	9,390
Vesting of phantom units, net of units withheld for withholding taxes	—	307	(1,582)	(1,582)
Common units issued in the public offering, net of underwriting fees and offering expenses	—	14,839	221,059	221,059
Common units issued for the acquisitions of IKAV and Sabinal (Note 3)	—	49,571	663,760	663,760
Balance at December 31, 2025	$ —	168,207	$ 1,989,389	$ 1,989,389

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

MACH NATURAL RESOURCES LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 142,984	$ 185,179	$ 346,558
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation, depletion, amortization and accretion	292,764	270,967	137,617
(Gain) loss on derivative instruments	(81,289)	18,854	(57,272)
Cash receipts on settlement of derivative contracts, net	48,576	17,307	4,417
Debt issuance costs and discount amortization	5,150	7,390	1,950
Impairment of oil and gas properties	90,430	—	—
Loss on debt extinguishment	18,540	—	—
Equity based compensation	9,390	6,531	3,440
Credit losses	5,245	2,240	1,746
Gain on sale of assets	(298)	(686)	(1)
Settlement of asset retirement obligations	(1,048)	(881)	(537)
Changes in operating assets and liabilities (decreasing) increasing cash:			
Accounts receivable	(7,903)	(46,870)	15,634
Revenue payable	(1,002)	39,869	19,029
Accounts payable and accrued liabilities	5,946	3,327	5,730
Inventories and other assets	(20,529)	2,065	13,431
Net cash provided by operating activities	506,956	505,292	491,742
Cash flows from investing activities			
Capital expenditures for oil and natural gas properties	(262,244)	(209,352)	(302,376)
Capital expenditures for other property and equipment	(8,302)	(10,964)	(12,428)
Acquisition of assets	(633,362)	(126,049)	(754,847)
Cash acquired from the acquisition of businesses	—	—	39,153
Proceeds from sales of oil and natural gas properties	4,243	39,107	3,305
Proceeds from sales of other property and equipment	503	942	36
Net cash (used in) investing activities	(899,162)	(306,316)	(1,027,157)
Cash flows from financing activities			
Proceeds from borrowings on term loan	450,000	—	811,000
Repayments of borrowings on term loan	(763,125)	(61,875)	—
Proceeds from Initial Public Offering and additional public offerings, net of offering costs	221,059	128,852	168,465
Purchases of units from exchanging members	—	—	(66,263)
Payments of debt extinguishment costs	(7,741)	—	—
Proceeds from borrowings on credit facility	1,104,150	—	68,000
Repayments of borrowings on credit facility	(404,150)	—	(235,000)
Debt issuance costs	(25,053)	(1,522)	(6,062)
Contributions from members	—	—	20,000
Distributions to members	—	—	(101,350)
Distributions to unitholders	(244,495)	(309,829)	—
Withholding taxes paid on vesting of phantom units	(1,582)	(1,618)	—
Net cash provided by (used in) financing activities	329,063	(245,992)	658,790
Net (decrease) increase in cash and cash equivalents	(63,143)	(47,016)	123,375
Cash and cash equivalents, beginning of period	105,776	152,792	29,417
Cash and cash equivalents, end of period	$ 42,633	$ 105,776	$ 152,792

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

MACH NATURAL RESOURCES LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.)

Unless otherwise stated or the context otherwise indicates, all references to the "Company" for time periods prior to the Corporate Reorganization refer to BCE-Mach III LLC and its subsidiary, the Company's predecessor for accounting purposes. For time periods subsequent to the Corporate Reorganization, this term refers to Mach Natural Resources LP and its subsidiaries.

1. Nature of Business

Mach Natural Resources LP ("the Company") is a Delaware limited partnership that was formed for the purpose of effectuating an initial public offering (the "Offering") that closed in October 2023. The Company's common units representing limited partnership interests (the "common units") are listed on The New York Stock Exchange under the symbol "MNR." The Company is an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas; the San Juan Basin region of New Mexico and Colorado; and the Permian Basin region of West Texas.

Following the Offering and Corporate Reorganization (as defined below), the Company became a holding partnership whose sole material asset consists of membership interests in Mach Natural Resources Intermediate LLC ("Intermediate"). Intermediate wholly owns Mach Natural Resources Holdco LLC ("Holdco"), and Holdco wholly owns each of the Company's operating subsidiaries. BCE-Mach III LLC (the "Predecessor") is the accounting predecessor to the Company for all periods prior to the Offering as discussed herein.

The Company's operations are governed by the provisions of its partnership agreement, executed by its general partner, Mach Natural Resources GP LLC (the "General Partner") and the limited partners. The General Partner is managed and operated by the board of directors and executive officers of the General Partner. The members of the board of directors of the General Partner are appointed by the members of the General Partner, BCE-Mach Aggregator and Mach Resources in proportion to their respective limited partnership ownership in the Company.

Management has evaluated how the Company is organized and managed and identified a single reportable segment, which is the exploration and production of oil, natural gas and NGLs. Management considers the Company's gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and its revenues are attributable to United States customers.

Corporate Reorganization

On October 25, 2023, the Company underwent a corporate reorganization (the "Corporate Reorganization") whereby (a) the owners who directly held membership interests in the Mach Companies prior to the Offering (the "Existing Owners") contributed 100% of their membership interests in each of the Mach Companies for a pro rata allocation of 100% of the limited partner interests in the Company with BCE-Mach III determined as the accounting acquirer of the net assets and operations of BCE-Mach and BCE-Mach II through a business combination, (b) the Company contributed 100% of its membership interests in the Mach Companies to Intermediate in exchange for 100% of the membership interests in Intermediate, and (c) Intermediate contributed 100% of its membership interests in the Mach Companies to Holdco in exchange for 100% of the membership interests in Holdco.

Initial Public Offering

On October 27, 2023, the Company completed the Offering of 10,000,000 common units at a price of $19.00 per unit to the public. The sale of Company's common units resulted in gross proceeds of $190.0 million to the Company and net proceeds of $168.5 million, after deducting underwriting fees and offering expenses. The material terms of the Offering are described in the Company's final prospectus, filed with the U.S. Securities and Exchange Commission ("SEC") on October 26, 2023, pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended (the "Securities Act").

The Company used $102.2 million of the proceeds to pay down the existing credit facilities of its operating subsidiaries (the "Pre-IPO Credit Facilities") and $66.3 million of the proceeds to purchase 3,750,000 common units from the existing common unit owners on a pro rata basis. After giving effect to the Offering and the transactions related thereto, the Company had 95,000,000 common units issued and outstanding.

2. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements included herein were prepared from records of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP") and include accounts of our wholly owned subsidiaries. Intercompany accounts and transactions have been eliminated upon consolidation. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Our financial and operating data for the year ended December 31, 2023 includes BCE-Mach III for the entire period and BCE-Mach LLC and BCE-Mach II LLC from October 25, 2023, the effective date of the acquisition as a result of the Corporate Reorganization.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the fair value determination of acquired assets and liabilities assumed in business combinations and the fair value estimates of commodity derivatives.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had an immaterial effect on the previously reported total assets, total liabilities, partners' capital, results of operations or cash flows.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable primarily consists of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for credit losses. The Company extends credit to joint interest owners and generally does not require collateral, but typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due.

As of December 31, 2025, the Company had three customers that represented approximately 20.0%, 13.5% and 13.2% of our total joint interest receivables. As of December 31, 2024, the Company had one customer that represented approximately 22.6% of our total joint interest receivables.

The Company establishes its allowance for credit losses equal to the estimable portions of accounts receivable for which failure to collect is expected to occur primarily based on a historical loss rate analysis. The Company estimates uncollectible amounts based on a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's expected ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company considers forecasts of future economic conditions in its estimate of expected credit losses and adjusts its allowance for expected credit losses when necessary. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for credit losses. At December 31, 2025 and December 31, 2024, the allowance for credit losses related to joint interest receivables was $9.1 million and $3.9 million, respectively, and the credit losses related to sales of oil and natural gas properties were not material. The increase in the allowance for credit losses was driven primarily by amounts billed to a royalty trust that owns a net profits interest on the properties acquired in the XTO Acquisition, for which collectibility is uncertain. The increase in the allowance for credit losses is presented as Other (expense) income, net in the Company's consolidated statement of operations.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet 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. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments in the statement of operations.

Oil and Natural Gas Operations

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as proved oil and natural gas properties. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities, which are expensed as incurred. Capitalized costs are depreciated using the unit of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $7.11, $8.03 and $6.86 for the years ended December 31, 2025, 2024 and 2023, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $268.2 million, $254.7 million and $126.4 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Under the full cost method, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each reporting period. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and natural gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on a quarterly basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. For the year ended December 31, 2025, the Company recorded an impairment as a result of the ceiling test calculation of $90.4 million. No impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2024 and 2023.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. As of December 31, 2025, and December 31, 2024, the Company had no properties excluded from the full cost pool.

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas, and NGL reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of gathering systems, processing plants, and a salt water disposal system. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed as incurred. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from two to 39 years. Depreciation expense for other property and equipment was $12.3 million, $9.0 million and $6.5 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment was recorded for the years ending December 31, 2025, 2024 and 2023.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production and midstream equipment not placed in service as of December 31, 2025, and 2024, and crude oil held in storage. The Company's production equipment primarily comprises oil and natural gas drilling or repair items such as tubing, casing and pumping units, as well as pipe for midstream operations, and are valued primarily using a weighted average cost method applied to specific classes of inventory items. Crude oil inventories are valued using the first-in, first-out inventory method. The components of inventory consisted of the following as of December 31, 2025 and 2024:

	December 31,	
	2025	2024
Production equipment	$ 42,122	$ 23,475
Crude oil in storage	1,389	826
Total	$ 43,511	$ 24,301

Debt Issuance Costs

The Company capitalized $14.8 million of new debt issuance costs related to the New Credit Agreement (as defined in Note 6) in the first half of 2025. The remaining unamortized debt issuance costs of $0.5 million from the Revolving Credit Agreement were retained and added to the additional amount of debt issuance costs associated with the New Credit Agreement and are being amortized over the New Credit Agreement's term.

The Company capitalized $3.8 million of new debt issuance costs related to the First Amendment to the New Credit Agreement (as defined in Note 6) on September 12, 2025.

Other assets include capitalized costs related to the New Credit Agreement of $19.1 million, net of accumulated amortization of $3.5 million as of December 31, 2025. As of December 31, 2024, other assets include capitalized costs related to the Revolving Credit Agreement of $2.6 million, net of accumulated amortization of $2.0 million. These costs are being amortized over the terms of the related credit agreements and are reported as interest expense on the Company's statements of operations.

The Company capitalized $6.5 million of new debt issuance costs related to the aggregate term loan commitments under the First Amendment to the New Credit Agreement (as defined in Note 6) on September 12, 2025.

Debt issuance costs and the discount associated with the Company's term loan are presented as a reduction of the carrying value of long-term debt on the Company's balance sheet. As of December 31, 2025, the Company had unamortized debt issuance costs of $5.9 million in relation to the aggregate term loan commitments under the First Amendment to the New Credit Agreement. As of December 31, 2024, the Company had unamortized debt issuance costs and discount of $11.8 million, in relation to the Term Loan Credit Agreement. On February 27, 2025, the Company wrote-off the remaining unamortized balance of the debt issuance costs and discount associated with the Term Loan Credit Agreement. See Note 6 for further discussion.

Income Taxes

The Company is a limited partnership treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company passed through to partners. As such, with the exception of the state of Texas, we are not a taxable entity, we do not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for our operations, except as described below. Net income for financial statement purposes may differ from taxable income reported to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

Limited partnerships are subject to state income taxes in the state of Texas. Due to immateriality, income taxes related to the Texas franchise tax have been included in general and administrative expenses on the statement of operations and no deferred tax amounts were calculated.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company did not recognize any potential interest or penalties in its financial statements for the year ended December 31, 2025. The Company's tax years 2024, 2023 and 2022 remain open for examination by state authorities.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction or saltwater disposal began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO activity for the years ended December 31, 2025 and 2024 (in thousands):

	Year Ended December 31,	
	2025	2024
Asset retirement obligation at beginning of period	$ 101,858	$ 85,094
Liabilities assumed in acquisitions	148,178	9,387
Liabilities incurred	200	765
Liabilities settled	(657)	(614)
Liabilities revised	—	23
Accretion expense	12,277	7,203
Asset retirement obligation at end of period	$ 261,856	$ 101,858

Revenue Recognition

Sales of oil, natural gas and NGLs are 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. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies. The payment date is usually within 30 to 90 days of the end of the calendar month in which the commodity is delivered.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production is historically volatile and unpredictable, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 7 for the Company's management of price volatility.

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statement of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGL are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statement of operations.

Midstream Revenue and Product Sales

The Company's gathering and processing revenue is generated from owned gathering and compression systems and processing plants acquired in the Company's acquisitions. The Company charges a gathering, compression, processing rate per MMBtu transported through the gathering system and processing plant. The Company also gathers and disposes of salt water from producing wells through an owned pipeline system and disposal wells. The Company charges a fixed rate per barrel of water for gathering and disposal. Fees are recognized as revenue based on measured volume at the specified delivery points when the associated service is performed.

Product sales are generated from the Company's sale of natural gas, oil and NGL production purchased from third parties and subsequently gathered and processed through the Company's owned midstream facilities. Product sales include activity from certain third-party percent-of-proceeds contracts where the Company keeps a contractually based percentage of proceeds from the sale of natural gas and NGL production, as payment for processing natural gas from the third parties. The Company retains control of the purchased natural gas and NGLs prior to delivery to the purchaser and satisfies its performance obligations by transferring control of the product at the delivery point and recognizes revenue based on the contract price received from the purchaser. The costs of buying natural gas, oil and NGL production from third-party shippers are included as costs of product sales on the statement of operations.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. The following purchasers each accounted for more than 10% of the Company's revenues for the periods indicated:

	Year Ended December 31,		
	2025	2024	2023
Purchaser A	23.3 %	32.2 %	52.6 %
Purchaser B	20.6 %	*	12.9 %
Purchaser C	*	12.7 %	*
Purchaser D	*	*	10.4 %

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* Purchaser did not account for greater than 10% of oil, natural gas, and NGL sales for the year.

The Company's receivables as of December 31, 2025 and 2024 from oil and gas sales are typically concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Contract Balances

Cash received relating to future performance obligations is deferred and recognized when all revenue recognition criteria are met. Receivables from contracts with customers were $160.2 million, $132.9 million and $78.1 million as of December 31, 2025, 2024 and 2023, respectively, and are included in accounts receivable – oil, gas, and NGL sales in the Company's consolidated balance sheets. Contract liabilities generated from such deferred revenue are not considered to be material as of December 31, 2025, 2024 and 2023. The Company's product sales and marketing contracts do not give rise to contract assets.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Revenues:			
Oil	$ 490,297	$ 554,007	$ 421,737
Natural gas	379,436	210,385	150,962
NGL	171,119	184,246	74,815
Gross oil, natural gas, and NGL sales	1,040,852	948,638	647,514
Transportation, gathering and marketing	(3,202)	(11,853)	(162)
Net oil, natural gas, and NGL sales	$ 1,037,650	$ 936,785	$ 647,352

Earnings per Common Unit

The Company's basic earnings per unit ("EPU") is computed based on the weighted average number of common units outstanding for the period. Diluted EPU includes the effect of the Company's phantom units if the inclusion of these units is dilutive. See Note 13 for additional information on the Company's EPU.

Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below (in thousands):

	Year ended December 31,		
	2025	2024	2023
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 62,559	$ 97,932	$ 8,373
Non-cash investing and financing activities:			
Change in accrued capital expenditures including amounts in accounts payable	$ (19,742)	$ 19,119	$ (19,104)
Asset retirement cost capitalized	$ 200	$ 765	$ 518
Right-of-use assets obtained in exchange for lease liabilities	$ 11,640	$ 9,055	$ 10,767
Equity issued in exchange for net assets acquired in business combinations	$ —	$ —	$ 227,644
Increase in accrued distributions	$ 773	$ 1,793	$ —
Change in accrued acquisition costs	$ 2,500	$ —	$ —
Common units issued for the acquisition of IKAV	$ 409,885	$ —	$ —
Common units issued for the acquisition of Sabinal	$ 253,875	$ —	$ —

Recent Accounting Pronouncements

In November 2024, the FASB issued ASU 2024-03, which requires disclosure of certain costs and expenses on an interim and annual basis in the notes to the financial statements. The guidance is effective for the first annual reporting period beginning after December 15, 2026, and interim reporting periods within annual reporting periods beginning after December 15, 2027. The amendments in this update are to be applied on a prospective basis, with the option for retrospective application. Early adoption is permitted. Management is currently evaluating this ASU to determine its impact on the Company's disclosures, but does not believe the adoption of the update will impact the Company's financial position, results of operations or liquidity.

3. Acquisitions and Divestitures

2025 Acquisitions

IKAV Acquisition

On July 9, 2025, the Company entered into a membership interest purchase agreement (the "IKAV Purchase Agreement") with VEPU Inc. and Simlog Inc. (collectively, the "IKAV Sellers"), pursuant to which the Company would acquire one hundred percent (100%) of the IKAV Sellers' membership interests in certain rights, titles and interests in oil and gas properties, rights and related assets located in certain designated lands in the San Juan Basin of New Mexico and Colorado. The transaction closed on September 16, 2025 for consideration of approximately $759.6 million comprised of (i) $349.8 million in cash and (ii) 30.6 million common units (the "IKAV Unit Consideration"), subject to certain customary purchase price adjustments (the "IKAV Acquisition"). The IKAV Unit Consideration had a value of approximately $409.9 million. The Company plans to finalize all such adjustments and complete the purchase price allocation in 2026 based on the terms of the IKAV Purchase Agreement.

This purchase was accounted for as a business combination, under the acquisition method, as the Company obtained control of a business by obtaining the legal right to use and develop the oil and natural gas properties included in the IKAV Purchase Agreement, as well as additional oil and gas related assets that can be used to enhance the value of the business. The table below reflects the preliminary fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. Any adjustments to preliminary amounts (such as accrued liabilities or other long-term liabilities) or recognition of additional assets acquired or liabilities assumed, may occur as additional information is obtained about facts and circumstances that existed as of the acquisition date during the measurement period, which will not exceed 12 months form the date of the IKAV Acquisition. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

	Initial IKAV Acquisition	Adjustments	As of December 31, 2025 IKAV Acquisition
Consideration transferred:			
Common units issued	30,611,264	—	30,611,264
Closing price of common units on September 15, 2025	$ 13.39	$ —	$ 13.39
Equity consideration	$ 409,885	$ —	$ 409,885
Cash consideration	349,763	—	349,763
Total acquisition consideration	$ 759,648	$ —	$ 759,648
Assets acquired:			
Proved oil and natural gas properties	$ 736,390	$ 31,450 (a)	$ 767,840
Accounts receivable	66,232	(5,865) (a)	60,367
Short-term derivative assets	5,470	—	5,470
Inventories	18,141	(4,007) (a)	14,134
Other current assets	15,319	(1,434) (a)	13,885
Other property, plant and equipment	113,867	(12,304) (a)	101,563
Other assets	11,430	(7,587) (a)	3,843
Total assets acquired	966,849	253	967,102
Liabilities assumed:			
Outstanding checks in excess of bank balance	1,574	—	1,574
Accounts payable and accrued liabilities	90,679	2,155 (a)	92,834
Revenue payable	14,519	1,888 (a)	16,407
Other current liabilities	331	—	331
Asset retirement obligations	86,948	—	86,948
Long-term derivative liabilities	2,187	—	2,187
Other long-term liabilities	10,963	(3,790) (a)	7,173
Total liabilities assumed	207,201	253	207,454
Net assets acquired	$ 759,648	$ —	$ 759,648

a. Adjustment reflects additional accounting data received and processed subsequent to the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

For the year ending December 31, 2025, the Company has recognized $87.2 million in revenues and earnings of $29.3 million related to the IKAV Acquisition. As of December 31, 2025, the Company has recognized transaction and advisory related expenses of $14.5 million, which are presented in general and administrative expense on the Company's statement of operations. Additionally, the Company capitalized certain debt issuance costs associated with the Company's New Credit Agreement in connection with the acquisition as discussed in Note 2.

Sabinal Acquisition

On July 9, 2025, the Company entered into a Purchase and Sale Agreement (the "Sabinal PSA") with Sabinal Energy Operating, LLC, Sabinal Resources, LLC and Sabinal CBP, LLC, pursuant to which the Company would acquire certain oil and gas assets located in certain designated lands in the Permian Basin. The transaction closed on September 16, 2025 for consideration of approximately $444.4 million comprised of (i) $199.3 million in cash and (ii) 19.2 million common units (the "Sabinal Unit Consideration"), subject to certain customary purchase price adjustments (the "Sabinal Acquisition"). On February 7, 2026, 0.2 million common units were cancelled from the Sabinal Unit Consideration as part of customary purchase price adjustments related to the final settlement, and the equity consideration had a final value of approximately $253.9 million.

This purchase was accounted for as an asset acquisition as substantially all of the fair value of acquired assets could be allocated to a single identified asset group of proved oil and natural gas properties. The table below reflects the fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

	Initial Sabinal Acquisition	Adjustments	Final Sabinal Acquisition
Consideration transferred:			
Common units issued	19,187,581	(227,547) (b)	18,960,034
Closing price of common units on September 15, 2025	$ 13.39	$ —	$ 13.39
Equity consideration	$ 256,922	$ (3,047) (b)	$ 253,875
Cash consideration	195,711	(5,254) (a)	190,457
Capitalized transaction costs	3,589	80 (a)	3,669
Less: purchase price adjustment receivable	(11,780)	11,780 (a)	—
Total acquisition consideration	$ 444,442	$ 3,559	$ 448,001
Assets acquired:			
Proved oil and natural gas properties	$ 489,681	$ 5,068 (a)	$ 494,749
Inventories	6,123	(1,548) (a)	4,575
Other property, plant and equipment	—	353 (a)	353
Other assets	144	—	144
Short-term derivative assets	5,793	—	5,793
Long-term derivative assets	3,933	3,313 (a)	7,246
Total assets acquired	505,674	7,186	512,860
Liabilities assumed:			
Accrued liabilities	2,876	3,741 (a)	6,617
Revenue payable	1,336	(114) (a)	1,222
Asset retirement obligations	57,020	—	57,020
Total liabilities assumed	61,232	3,627	64,859
Net assets acquired	$ 444,442	$ 3,559	$ 448,001

a. Adjustment reflects additional accounting data received and processed subsequent to the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

b. Adjustment reflects a cancellation of shares transferred. The initial purchase price allocation considered available data at the time of disclosure.

XTO Acquisition

On March 25, 2025, the Company entered into an Equity Interest Purchase Agreement (“XTO EIPA”), pursuant to which the Company would acquire certain oil and gas assets located in Oklahoma, Kansas and Wyoming, for consideration of $60.0 million in cash, subject to certain customary purchase price adjustments (the “XTO Acquisition”).

The transaction closed on April 30, 2025. This purchase was accounted for as a business combination, under the acquisition method, as the Company obtained control of a business by obtaining the legal right to use and develop the oil and natural gas properties included in the XTO EIPA, as well as additional oil and gas related assets that can be used to enhance the value of the business. The table below reflects the fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

	Initial XTO Acquisition	Adjustments		Final XTO Acquisition
Consideration transferred:				
Cash consideration	$ 77,893	$ 361	(a)	$ 78,254
Less: purchase price adjustment receivable	—	(2,105)	(a)	(2,105)
Total acquisition consideration	$ 77,893	$ (1,744)		$ 76,149
Assets acquired:				
Proved oil and natural gas properties	$ 65,530	$ 5,495	(a)	$ 71,025
Accounts receivable – joint interest	2,344	(2,281)	(a)	63
Other property and equipment	6,417	(782)	(a)	5,635
Other assets	9,576	(3,850)	(a)	5,726
Total assets acquired	83,867	(1,418)		82,449
Liabilities assumed:				
Revenue payable	1,354	326	(a)	1,680
Accrued liabilities	444	—		444
Asset retirement obligations	4,176	—		4,176
Total liabilities assumed	5,974	326		6,300
Net assets acquired	$ 77,893	$ (1,744)		$ 76,149

a. Adjustment reflects additional accounting data received and processed subsequent to the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

Flycatcher Acquisition

On December 20, 2024, the Company entered into a Purchase and Sale Agreement (the “Flycatcher PSA”) to purchase certain oil and gas assets near our recently acquired oil and gas assets located in the Ardmore Basin of Oklahoma for consideration of $29.8 million in cash, subject to certain customary purchase price adjustments (the “Flycatcher Acquisition”). The Company plans to finalize all such adjustments and complete the purchase price allocation in 2026 based on terms of the Flycatcher PSA. The Company does not expect post-closing adjustments to be material and they would primarily affect the value of proved oil and gas properties.

The transaction closed on January 31, 2025 and the Company borrowed $23.0 million on the Revolving Credit Agreement to fund the Flycatcher Acquisition. This purchase was accounted for as an asset acquisition as substantially all of the fair value of acquired assets could be allocated to a single identified asset group of proved oil and natural gas properties. The table below reflects the preliminary fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

	Flycatcher Acquisition	
Consideration transferred:		
Cash consideration	$	24,141
Capitalized transaction costs		182
Total acquisition consideration	$	24,323
Assets acquired:		
Proved oil and natural gas properties	$	26,566
Other assets		8
Total assets to be acquired		26,574
Liabilities assumed:		
Revenue suspense		2,217
Asset retirement obligations		34
Total liabilities assumed		2,251
Net assets acquired	$	24,323

2024 Acquisitions

Ardmore Basin Acquisition

On August 26, 2024, the Company entered into a Consent Agreement with the purchaser under a Purchase and Sale Agreement (the “Ardmore Basin PSA”) to acquire oil and gas properties in the Ardmore Basin of Oklahoma for consideration of approximately $98.0 million in cash, subject to certain customary purchase price adjustments (the “Ardmore Basin Acquisition”).

The transaction closed on October 1, 2024. This purchase was accounted for as an asset acquisition as substantially all of the fair value of acquired assets could be allocated to a single identified asset group of proved oil and natural gas properties. The table below reflects the fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

	Initial Ardmore Basin Acquisition	Adjustments	Final Ardmore Basin Acquisition
Consideration transferred:			
Cash consideration	$ 78,317	$ (2,966) (a)	$ 75,351
Capitalized transaction costs	1,295	49 (a)	1,344
Less: purchase price adjustment receivable	(2,735)	2,735 (a)	—
Total acquisition consideration	$ 76,877	$ (182)	$ 76,695
Assets acquired:			
Proved oil and natural gas properties	$ 85,663	$ (269) (a)	$ 85,394
Other assets	13	—	13
Total assets to be acquired	85,676	(269)	85,407
Liabilities assumed:			
Revenue suspense	8,636	(87) (a)	8,549
Asset retirement obligations	163	—	163
Total liabilities assumed	8,799	(87)	8,712
Net assets acquired	$ 76,877	$ (182)	$ 76,695

a. Adjustment reflects additional accounting data received and processed subsequent to the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

Western Kansas Acquisition

On August 9, 2024, the Company executed a purchase and sale agreement (the “Western Kansas PSA”) to purchase certain oil and gas properties in Kansas and Oklahoma for consideration of $38.0 million in cash, subject to certain customary purchase price adjustments (the “Western Kansas Acquisition”).

The transaction closed on September 25, 2024. This purchase was accounted for as an asset acquisition as substantially all of the fair value of acquired assets could be allocated to a single identified asset group of proved oil and natural gas properties. The table below reflects the fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

	Initial Western Kansas Acquisition	Adjustments		Final Western Kansas Acquisition
Consideration transferred:				
Cash consideration	$ 36,657	$ 606	(a)	$ 37,263
Capitalized transaction costs	—	301	(a)	301
Total acquisition consideration	$ 36,657	$ 907		$ 37,564
Assets acquired:				
Proved oil and natural gas properties	$ 45,582	$ 993	(a)	$ 46,575
Other property and equipment	400	—		400
Other assets	123	97	(a)	220
Total assets to be acquired	46,105	1,090		47,195
Liabilities assumed:				
Revenue suspense	333	74	(a)	407
Asset retirement obligations	9,115	109	(a)	9,224
Total liabilities assumed	9,448	183		9,631
Net assets acquired	$ 36,657	$ 907		$ 37,564

a. Adjustment reflects additional accounting data received and processed subsequent to the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

2023 Acquisitions

Paloma Partners IV, LLC

On November 10, 2023, the Company entered into a purchase and sale agreement (the "Paloma PSA") with Paloma Partners IV, LLC pursuant to which the Company agreed to purchase certain interests in oil and gas properties, rights and related assets located in Blaine, Caddo, Canadian, Custer, Dewey, Grady, Kingfisher and McClain Counties, Oklahoma (the "Paloma Assets").

On December 28, 2023, the Company completed the acquisition of the Paloma Assets (the "Paloma Acquisition") in accordance with the terms of the Paloma PSA for a purchase price of approximately $815,000,000 in cash. The Company utilized borrowings under the Term Loan Credit Agreement to fund the Paloma Acquisition.

The Paloma Acquisition was accounted for as an asset acquisition as substantially all of the gross fair value of the Paloma Assets was concentrated in proved oil and natural gas properties, which were considered to be a group of similar identifiable assets. The table below reflects the fair value of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of assets acquired and liabilities assumed (in thousands):

	Initial Paloma Acquisition	Adjustments		Final Paloma Acquisition
Consideration transferred:				
Cash consideration	$ 748,587	$ (23,756)	(a)	$ 724,831
Capitalized transaction costs	1,695	1,295	(a)	2,990
Less: purchase price adjustment receivable	(15,160)	15,160	(a)	—
Total acquisition consideration	$ 735,122	$ (7,301)		$ 727,821
Assets acquired:				
Accounts receivable	$ 4,239	$ —		$ 4,239
Inventories	166	—		166
Proved oil and natural gas properties	750,476	268	(a)	750,744
Total assets to be acquired	754,881	268		755,149
Liabilities assumed:				
Revenue payable	18,295	7,569	(a)	25,864
Asset retirement obligations	1,464	—		1,464
Total liabilities assumed	19,759	7,569		27,328
Net assets acquired	$ 735,122	$ (7,301)		$ 727,821

a. Adjustment reflects additional accounting data received and processed subsequent to the acquisition date. The initial purchase price allocation considered available data at the time of disclosure.

BCE-Mach LLC and BCE-Mach II LLC

On October 25, 2023, as part of the Corporate Reorganization, the Existing Owners contributed all of their equity interests in BCE-Mach, BCE-Mach II and the Predecessor to the Company in exchange for 100% of the limited partnership interests in the Company to effectuate the acquisition. While there was a high degree of common ownership, the Mach Companies were not under common control for financial reporting purposes. The Predecessor was identified as the accounting acquirer of BCE-Mach and BCE-Mach II which have been accounted for as business combinations under the acquisition method of accounting under U.S. GAAP.

The following table presents the fair value of consideration transferred by the Company for each of the acquisitions (amounts in thousands, except unit and per unit amounts):

(Amounts in thousands, except share amounts)	BCE-Mach LLC	BCE-Mach II LLC
Common units issued for acquisition	7,765,625	4,215,625
Offering price of common units	$ 19.00	$ 19.00
Total acquisition consideration	$ 147,547	$ 80,097

The tables below reflect the fair value estimates of the assets acquired and liabilities assumed as of the acquisition date. See Note 8 for additional information regarding fair value measurements. Below is a reconciliation of assets acquired and liabilities assumed (in thousands):

	BCE-Mach LLC	BCE-Mach II LLC
Assets acquired:		
Cash and cash equivalents	$ 30,350	$ 8,803
Accounts receivable	32,042	11,541
Other current assets	18,303	2,331
Proved oil and natural gas properties	184,840	98,800
Other long-term assets	11,176	7,811
Total assets to be acquired	276,711	129,286
Liabilities assumed:		
Accounts payable and accrued liabilities	17,312	3,659
Revenue payable	29,390	15,317
Other current liabilities	1,361	446
Long-term debt	65,000	17,100
Asset retirement obligations	14,369	11,589
Other long-term liabilities	1,732	1,078
Total liabilities assumed	129,164	49,189
Net assets acquired	$ 147,547	$ 80,097

Proved properties were valued using an income approach based on underlying reserves projections as of the acquisition date. The income approach is considered a Level 3 fair value estimate and includes significant assumptions of future production, commodity prices, operating and capital cost estimates, the weighted average cost of capital for industry peers, which represents the discount factor and risk adjustment factors based on reserve category. Price assumptions were based on observable market pricing, adjusted for historical differentials, while cost estimates were based on current observable costs inflated based on historical and expected future inflation.

The results of operations attributable to the BCE-Mach acquisition from the acquisition date through December 31, 2023 have been included in the consolidated statement of operations for the year ended December 31, 2023, and include $26.3 million of total revenue and $6.8 million of net income. The results of operations attributable to the BCE-Mach II acquisition from the acquisition date through December 31, 2023 have been included in the consolidated statement of operations for the year ended December 31, 2023, and include $5.1 million of total revenue and $22 thousand of net income.

Hinkle Oil and Gas, Inc.

On June 28, 2023 the Company executed a purchase and sale agreement with Hinkle Oil and Gas, Inc. for the sale of certain oil and gas properties in Oklahoma for $20.0 million, subject to certain customary adjustments. The transaction closed on August 11, 2023. This purchase was accounted for as an asset acquisition as substantially all of the fair value of acquired assets could be allocated to a single identified asset group of proved oil and natural gas properties.

Business Combination Pro Forma Disclosures

The following table summarizes the unaudited pro forma consolidated financial information of the Company for the years ended December 31, 2025, 2024 and 2023 as if the IKAV Acquisition had occurred on January 1, 2024 and the acquisitions of BCE-Mach and BCE-Mach II had occurred on January 1, 2022 (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Total revenues	$ 1,392,996	$ 1,258,819	$ 914,400
Net income	256,949	294,924	351,967

The unaudited pro forma financial information is not necessarily indicative of the operating results that would have occurred had the business combinations been completed on the dates indicated and is not necessarily indicative of future results of operations of the combined company. The unaudited pro forma financial information for the years ended December 31, 2025, 2024 and 2023 is a result of combining the statements of operations of the Company with the pre-acquisition results of the acquired operations, with pro forma adjustments for revenues and expenses. The unaudited pro forma financial information excludes any anticipated cost savings as a result of the acquisitions.

Divestitures

On June 26, 2024, the Company executed a purchase and sale agreement to sell certain acreage not attributable to the Company's proved developed reserves. The proceeds from the sale were approximately $38.0 million, and were applied as a credit against the full cost pool with no gain or loss recognized.

4. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	As of December 31,	
	2025	2024
Oil and natural gas properties		
Proved properties	$ 4,017,896	$ 2,419,998
Accumulated depreciation, depletion, amortization and impairment	(879,253)	(520,641)
Oil and natural gas properties, net	$ 3,138,643	$ 1,899,357
Other property and equipment		
Gas gathering system	$ 127,620	$ 35,241
Gas processing plants	47,902	35,949
Water disposal assets	30,292	28,977
Vehicles	12,771	6,303
Other assets	11,680	9,005
Total other property and equipment	230,265	115,475
Accumulated depreciation	(35,511)	(23,710)
Total other property and equipment, net	$ 194,754	$ 91,765

5. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	As of December 31,	
	2025	2024
Operating expenses	$ 36,637	$ 12,489
Capital expenditures	19,423	24,027
Payroll costs	9,246	7,842
Derivative settlements	1,178	149
Ad-valorem, severance and other tax	30,562	4,622
Midstream shipper payable	1,792	1,160
Interest payable	3,388	—
Purchaser payable	9,812	—
General, administrative, and other	3,527	2,631
Total accrued liabilities	$ 115,565	$ 52,920

6. Long-Term Debt

New Credit Agreement

On February 27, 2025, the Company entered into the New Credit Agreement, among the Company, the lenders and issuing banks party thereto from time to time and Truist Bank, as the administrative agent and collateral agent. The New Credit Agreement is secured by substantially all of our assets.

The New Credit Agreement has (i) an initial borrowing base and elected commitment amount of $750.0 million, with a maximum commitment amount of $2.0 billion subject to borrowing base availability, (ii) a maturity date of February 27, 2029 and (iii) an interest rate equal to, at the Company's election, (a) term SOFR (subject to a 0.10% per annum adjustment) plus a margin ranging from 3.00-4.00% per annum or (b) a base rate plus a margin ranging from 2.00-3.00% per annum, with the margin dependent upon borrowing base utilization at the time of determination. The Company is also required to pay a commitment fee of 0.50% per annum on the daily unused portion of the current aggregate commitments under the New Credit Agreement.

The New Credit Agreement's borrowing base is redetermined semi-annually, in April and October. The New Credit Agreement requires the Company to maintain as of the last day of each fiscal quarter (i) a consolidated total net leverage ratio of less than or equal to 3.00 to 1.00 and (ii) a current ratio of no less than 1.00 to 1.00.

The Company used borrowings from the New Credit Agreement, together with cash on hand and proceeds from the February 2025 Offering, to repay the Term Loan Credit Agreement and the Revolving Credit Agreement in full.

On September 12, 2025, the Company entered into the First Amendment. The First Amendment, among other things, (a) removes the 0.10% per annum credit spread adjustment otherwise applicable to the determination of Term SOFR (as defined in the New Credit Agreement), (b) excludes up to $750.0 million in principal amount of Borrowing Base Reduction Debt (as defined in the New Credit Agreement) issued prior to December 31, 2025 from the provisions otherwise requiring a borrowing base reduction as a result of the issuance of such indebtedness and (c) provides for (i) a $700.0 million aggregate increase in the borrowing base under the Credit Agreement and (ii) the establishment of aggregate term loan commitments (prior to giving effect to any prior funding of term loans) in an amount of $450.0 million and the funding of any unfunded term loan commitments thereunder and increase the Aggregate Elected Revolving Commitment Amount (as defined in the Credit Agreement) to $1.0 billion.

The Company used increased borrowings from the amended Credit Agreement, together with the IKAV Unit Consideration and the Sabinal Unit Consideration, to fund the IKAV Acquisition and the Sabinal Acquisition.

As of December 31, 2025, there were $1.15 billion of outstanding borrowings under the New Credit Agreement with $5.0 million in outstanding letters of credit, and the remaining availability under the New Credit Agreement was $295.0 million. The effective interest rate as of December 31, 2025 was 7.7%.

Prior Credit Facilities

Term Loan Credit Agreement and Revolving Credit Agreement

On December 28, 2023, the Company entered into (i) a senior secured term loan credit agreement (the "Term Loan Credit Agreement") with the lenders party thereto, Texas Capital Bank, as agent, and Chambers Energy Management, LP, as arranger, and (ii) a senior secured revolving credit agreement (the "Revolving Credit Agreement," and together with the Term Loan Credit Agreement, the "Credit Agreements") with a syndicate of lenders, including MidFirst Bank as the administrative agent.

Loans advanced to the Company under the Term Loan Credit Agreement were secured by a first-priority security interest on substantially all of our assets. The Term Loan Credit Agreement had (i) an aggregate principal amount of $825.0 million, (ii) a maturity date of December 31, 2026 and (iii) an interest rate equal to the three-month SOFR plus 6.50% plus a credit spread adjustment equal to 0.15%, provided that the three-month SOFR will not be less than 3.00%. As of December 31, 2024, there were $763.1 million of outstanding borrowings under the Term Loan Credit Agreement. The effective interest rate as of December 31, 2024 was 12.3%.

On February 27, 2025, the Company used borrowings from the New Credit Agreement, together with cash on hand and proceeds from the February 2025 Offering, to repay the existing amounts outstanding under, and terminate, the Term Loan Credit Agreement. The termination of the Term Loan Credit Agreement was treated as a debt extinguishment. Accordingly, the Company recorded $18.5 million in debt extinguishment costs, which included $10.8 million related to the write-off of all unamortized discount and debt issuance costs and $7.7 million related to prepayment penalties.

Loans advanced to the Company under the Revolving Credit Agreement were secured by a super-priority security interest on substantially all of our assets. The Revolving Credit Agreement had (i) a maximum available principal amount of $75.0 million, with maximum commitments currently equal to $75.0 million, (ii) a maturity date of December 28, 2026 and (iii) an interest rate equal to the one, three, or six month SOFR, at the Company's election, plus a credit spread adjustment equal to 0.10%, 0.15%, or 0.25%, respectively, in each case, plus 3.00%, provided that the applicable tenor SOFR will not be less than 3.50%. The Revolving Credit Agreement included customary covenants, mandatory repayments and events of default of financings of this type. The Company was also required to pay a commitment fee of 0.50% per annum on the average daily unused portion of the current aggregate commitments under the Revolving Credit Agreement. As of December 31, 2024, the Revolving Credit Agreement was undrawn, and there was $5.0 million in outstanding letters of credit, which reduce the amount available to borrow under the Revolving Credit Agreement.

On January 31, 2025, the Company borrowed $23.0 million under the Revolving Credit Agreement to fund the Flycatcher Acquisition.

On February 27, 2025, the Company used borrowings under the New Credit Agreement to repay the existing amounts outstanding under and terminate the existing Revolving Credit Agreement. The termination of the Revolving Credit Agreement was treated as a debt modification based on the composition of the bank syndication in the New Credit Agreement and the change in borrowing capacity.

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.

BCE-Mach III Credit Facility

On May 19, 2020, the Predecessor entered into a credit agreement for a revolving credit facility (the "BCE-Mach III Credit Facility") with a syndicate of banks, including MidFirst Bank ("MidFirst"), who served as administrative agent and issuing bank. The BCE-Mach III Credit Facility provided for a maximum of $300.0 million, subject to commitments of $100.0 million and was scheduled to mature in May 2026. Outstanding obligations under the BCE-Mach III Credit Facility were secured by substantially all of the Predecessor's assets. The amount available to be borrowed under the BCE-Mach III Credit Facility was subject to a borrowing base that was redetermined semiannually each May and November in an amount determined by the lenders.

The credit agreement contained various affirmative, negative and financial maintenance covenants. These covenants, among other things, limited additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. The BCE-Mach III Credit Facility required mandatory payments when the consolidated cash balance of the Predecessor exceeded $20.0 million.

At the Predecessor's election, outstanding borrowings under the credit agreement bore interest at a per annum rate elected by the Predecessor that was equal to an alternative base rate (which was equal to the greatest of the most recent prime rate, the Federal Funds effective rate plus 0.5%, and 1-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranged from 2.0% to 3.0% in the case of the alternate base rate and from 3.25% to 4.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding. The Predecessor was obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the commitment, which fee was also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of December 31, 2023 was 7.7%.

On November 10, 2023, there was $91.9 million outstanding under the BCE-Mach III Credit Facility, which was repaid and terminated when the Company entered into the November 2023 Credit Facility. The termination of the BCE-Mach III Credit Facility was treated as a debt modification, due to the makeup of banks in each credit facility syndicate. The Company wrote off the issuance costs associated with banks exiting the credit facility, and evaluated the change in borrowing capacity with remaining syndicate members and determined no additional issuance cost write offs were necessary. Total write offs of issuance costs were $14.0 thousand, and were included in the Company's interest expense on the statement of operations.

BCE-Mach Credit Facility

On October 25, 2023, the Company assumed the revolving credit facility (the "BCE-Mach Credit Facility") between BCE-Mach and a syndicate of banks, including MidFirst Bank who served as sole book runner and lead arranger. Outstanding obligations under the BCE-Mach Credit Facility were secured by substantially all of BCE-Mach's assets. The credit agreement provided for a revolving credit facility in a maximum outstanding amount of $200.0 million, subject to commitments of $100.0 million. As of October 25, 2023, $65.0 million was outstanding under the BCE-Mach Credit Facility along with $5.0 million in outstanding letters of credit, which reduced the availability under the credit facility on a dollar-for-dollar basis. On November 10, 2023, the Company repaid all amounts outstanding under the BCE-Mach Credit Facility and entered into the November 2023 Credit Facility and terminated the BCE-Mach Credit Facility.

BCE-Mach II Credit Facility

On October 25, 2023, the Company assumed the revolving credit facility (the "BCE-Mach II Credit Facility") between BCE-Mach II and a syndicate of banks, including East West Bank, who served as sole book runner and lead arranger. Outstanding obligations under the BCE-Mach II Credit Facility were secured by substantially all of BCE-Mach II's assets. The credit agreement provided for a revolving credit facility in a maximum outstanding amount of $250.0 million, subject to a borrowing base of $26.0 million. As of October 25, 2023, $17.1 million was outstanding under the BCE-Mach II Credit Facility. On October 31, 2023, the Company repaid all amounts outstanding under the BCE-Mach II Credit Facility. On November 10, 2023, the Company entered into the November 2023 Credit Facility and terminated the BCE-Mach II Credit Facility.

November 2023 Credit Facility

On November 10, 2023, Holdco, a subsidiary of the Company, entered into the November 2023 Credit Facility with a syndicate of banks, including MidFirst Bank who served as sole book runner and lead arranger. Outstanding obligations under the November 2023 Credit Facility were secured by substantially all of Holdco's assets, comprising the assets of the Mach Companies. In connection with entering into the November 2023 Credit Facility, each of the Pre-IPO Credit Facilities were terminated.

The aggregate principal amount of loans outstanding under the November 2023 Credit Facility as of November 10, 2023 was $125.0 million, in addition to $5.0 million of issued letters of credit. The November 2023 Credit Facility provided for a revolving credit facility in an aggregate maximum amount of $1.0 billion, with an initial borrowing base of $600.0 million, subject to commitments of $200.0 million. On December 28, 2023, the Company entered into the Credit Agreements and terminated the November 2023 Credit Facility. The termination of the November 2023 Credit Facility was treated as a debt modification, due to the makeup of banks in each credit facility syndicate. The Company wrote off the issuance costs associated with banks exiting the credit facility, and evaluated the decrease in borrowing capacity with remaining syndicate members to write off the proportional amount of issuance costs in comparison to the reduction in borrowing capacity. Total write offs of issuance costs were $1.5 million, and were included in the Company's interest expense on the statement of operations.

7. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps, basis swaps and costless collars. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 8 for additional information regarding fair value measurements.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty. Crude oil derivative contracts are indexed and settled based on NYMEX WTI pricing. Natural gas derivative contracts are indexed and settled based on NYMEX Henry Hub ("NYMEX HH") pricing and EP San Juan ("EP SJ").

The following table summarizes the open fixed price swap positions as of December 31, 2025, related to oil production:

Period	Index	Volume (Mbbl)	Weighted Average Fixed Price
2026	NYMEX WTI	3,436	$ 66.13
2027	NYMEX WTI	1,858	63.20

The following table summarizes the open fixed price swap positions as of December 31, 2025, related to natural gas production:

Period	Index	Volume (Bbtu)	Weighted Average Fixed Price
2026	NYMEX HH	14,587	$ 3.56
2026	EP SJ	15,925	3.39
2027	NYMEX HH	5,768	3.86
2027	EP SJ	2,447	3.59
2028	NYMEX HH	3,758	3.68
2028	EP SJ	2,682	2.72
2029	NYMEX HH	4,544	3.43

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

The following table summarizes the open costless collar positions as of December 31, 2025, related to oil production:

Period	Index	Volume (Mbbl)	Weighted Average Floor Price	Weighted Average Ceiling Price
2026	NYMEX WTI	549	$ 60.00	$ 78.05
2027	NYMEX WTI	181	62.50	71.25

In addition, the Company has entered into oil basis swap positions. These instruments are arrangements that guarantee a fixed price differential to Argus WTI Midland TMA from a specified delivery point. The Company receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

The following table summarizes the open basis swap positions as of December 31, 2025, related to oil production:

Period	Index	Volume (Mbbl)	Weighted Average Fixed Price
2026	Argus TMA	548	$ 1.25

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following tables presents the gross amounts of recognized derivative assets, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	As of December 31,	
	2025	2024
Derivative contracts – current, gross	$ 43,974	$ 14,696
Netting arrangements	(1,468)	(627)
Derivative contracts – current, net	$ 42,506	$ 14,069
Derivative contracts – long-term, gross	$ 12,519	$ 2,182
Netting arrangements	(27)	(1,542)
Derivative contracts – long-term, net	$ 12,492	$ 640

The following tables presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	As of December 31,	
	2025	2024
Derivative contracts – current, gross	$ (1,468)	$ (6,860)
Netting arrangements	1,468	627
Derivative contracts – current, net	$ —	$ (6,233)
Derivative contracts – long-term, gross	$ (2,989)	$ (6,415)
Netting arrangements	27	1,542
Derivative contracts – long-term, net	$ (2,962)	$ (4,873)

Gains and Losses. The following table presents the settlement and mark-to-market ("MTM") gains and losses on oil and natural gas derivatives presented as a gain or loss on derivatives in the statement of operations for the years ended December 31, 2025, 2024 and 2023 (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Settlements of oil derivatives	$ 17,814	$ (5,301)	$ (5,750)
Settlements of natural gas derivatives	31,366	22,758	14,196
MTM gains (losses) on oil derivatives, net	30,514	(13,377)	27,559
MTM gains (losses) on natural gas derivatives, net	1,595	(22,934)	21,267
Total gains (losses) on derivative contracts	$ 81,289	$ (18,854)	$ 57,272

8. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2025 and 2024 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
As of December 31, 2025				
Assets:				
Commodity derivative instruments	$ —	$ 56,493	$ —	$ 56,493
Liabilities:				
Commodity derivative instruments	$ —	$ (4,457)	$ —	$ (4,457)
As of December 31, 2024				
Assets:				
Commodity derivative instruments	$ —	$ 16,878	$ —	$ 16,878
Liabilities:				
Commodity derivative instruments	$ —	$ (13,275)	$ —	$ (13,275)

Fair Value on a Non-Recurring Basis

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

Business combinations

Proved properties acquired as a result of business combinations were valued using an income approach based on underlying reserves projections as of the acquisition date. The income approach is considered a Level 3 fair value estimate and includes significant assumptions of future production, commodity prices, operating and capital cost estimates, the weighted average cost of capital for industry peers, which represents the discount factor, and risk adjustment factors based on reserve category. Price assumptions were based on observable market pricing, adjusted for historical differentials, while cost estimates were based on current observable costs inflated based on historical and expected future inflation.

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair value due to the short-term maturities of these instruments.

The carrying amount of the Company's Credit Agreements approximate fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

9. Equity Compensation Plans

Equity-based compensation includes unit-based payment awards that are issued to employees and non-employees in exchange for services provided to the Company. Equity-classified unit-based payment awards are recognized at fair value on the grant date and amortized over the requisite service period. For awards with service-based vesting conditions only, the Company recognizes compensation cost using straight-line attribution. The Company uses accelerated attribution for awards that contain market or performance-based vesting conditions. The Company recognizes forfeitures as they occur. Equity-based compensation is presented within general and administrative expense on our consolidated statements of operations.

Post-Offering Grants

On October 27, 2023, the Company adopted a new long-term incentive plan (the "Long-Term Incentive Plan") for employees, consultants and directors in connection with the Offering. The Company issues phantom units ("Time-Based

Phantom Units") to certain employees of Mach Resources LLC ("Mach Resources") and directors of the Company as compensation for services rendered to the Company. The Time-Based Phantom Unit awards for all employees of Mach Resources vest ratably on the first three anniversaries of the date of the grant, subject to the employee's continued employment. Within 60 days of the vesting of a Time-Based Phantom Unit, the employee will receive a common unit of the Company. Each Time-Based Phantom Unit was granted with a corresponding distribution equivalent right ("DER"), which entitles the employee to receive a payment equal to the total distributions paid by the Company in respect of a common unit of the Company during the time the applicable phantom unit is outstanding. Payment of a DER occurs when its corresponding phantom unit vests, and in the event such phantom unit is forfeited, the corresponding DER is also forfeited.

	Time-Based Phantom Units	Weighted Average Grant Date Fair Value	Performance Phantom Units	Weighted Average Grant Date Fair Value
Unvested at December 31, 2023	709,545	$ 18.80	—	$ —
Granted[1]	626,109	$ 16.44	47,796	$ 25.21
Vested	(292,493)	$ 18.80	(7,242)	$ 29.02
Forfeited/Cancelled[2]	(19,841)	$ 18.75	(1,932)	$ 20.44
Unvested at December 31, 2024	1,023,320	$ 17.36	38,622	$ 24.88
Granted	1,220,591	$ 12.93	72,759	$ 19.61
Vested	(424,753)	$ 17.40	—	$ —
Forfeited/Cancelled[2]	(70,651)	$ 16.22	(19,853)	$ —
Unvested at December 31, 2025	1,748,507	$ 14.31	91,528	$ 21.44

(1) For performance phantom units, the impacts of performance share unit grants that vested higher than 100% of the target are included in this row.
(2) For performance phantom units, the impacts of performance share unit grants that vested at 0% are included in this row.

Total non-cash compensation cost related to the Time-Based Phantom Units was $8.5 million and $6.1 million for the years ended December 31, 2025 and December 31, 2024, respectively. As of December 31, 2025, there was $22.5 million of unrecognized compensation cost related to phantom units that is expected to be recognized over a weighted average period of approximately 2.26 years.

The aggregate fair value of share based awards that vested during the year ended December 31, 2025 was approximately $5.3 million based on the unit price at the time of vesting.

The Company has awarded performance based phantom units ("Performance Phantom Units") to certain of its executive officers under the Long-Term Incentive Plan. The number of common units issued pursuant to each Performance Phantom Unit award agreement will be from 0% to 200% of the target number of Performance Phantom Units thereunder based on a combination of the Company's (i) total shareholder return ("TSR"), (ii) relative TSR compared to the TSR of the companies in the Company's designated peer group and (iii) total recordable incident rate, in each case, for the applicable performance period. The Performance Phantom Unit awards are broken into two categories: long-term performance units, which have a three-year performance period, and short-term performance units, which are broken into three separate one-year tranches with performance periods in each one-year period. Performance Phantom Units vest based on the achievement of the applicable performance metrics at the end of the applicable performance period, subject generally to the applicable executive officer's continued employment through such performance period. Within 60 days of the vesting of a Performance Phantom Unit, the executive officer will receive a common unit of the Company. Each Performance Phantom Unit was granted with a corresponding DER. Payment of any such DER occurs when its corresponding Performance Phantom Unit vests, and in the event such Performance Phantom Unit is forfeited, the corresponding DER is also forfeited. The grant date fair values of the Performance Phantom Units with market conditions were determined using the Monte Carlo simulation method and are being recorded ratably from the grant date to the end of the applicable performance period.

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

Grant date	May 3, 2024	January 1, 2025
Period for volatility, correlations, and risk-free rate	2.66 years	3.00 years
Risk-free interest rate	4.61%	4.23%
Implied equity volatility	57.25%	50.57%
Unit price on date of grant	$20.44	$17.18

Total non-cash compensation cost related to the Performance Phantom Units was $0.9 million and $0.4 million for the years ended December 31, 2025 and December 31, 2024, respectively. As of December 31, 2025, there was $1.0 million of unrecognized compensation cost related to phantom units that is expected to be recognized over a weighted average period of approximately 1.64 years. The Long-Term Incentive Plan initially authorized the Company to issue 9.5 million units, and the total amount authorized increases by 5% of the outstanding units at the end of each year.

Predecessor Grants

As part of the Predecessor's amended and restated LLC agreement as of March 25, 2021, incentive units (Class B Units) and Class A-2 Units were issued to certain employees of Mach Resources as compensation for services to be rendered to the Predecessor. In determining the appropriate accounting treatment, the Predecessor considered the characteristics of the awards in terms of treatment as stock-based compensation.

The incentive units were subject to graded vesting over a period of approximately 3 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units would forfeit unvested incentive units upon ceasing to be an employee of Mach Resources, excluding limited exceptions. Holders of incentive units were able to participate in distributions upon the Predecessor meeting a certain requisite financial internal rate of return threshold as defined in the Predecessor's amended LLC agreement.

A summary of the Predecessor's incentive unit awards as of December 31, 2025 is as follows:

	Predecessor Class B Units	Weighted Average Grant Date Fair Value
Unvested at December 31, 2022	6,668	$ 2,378.80
Vested	(6,668)	$ 2,378.80
Unvested at December 31, 2023	—	N/A

On October 25, 2023, all unvested Class B Units immediately vested and were exchanged for common units in the Company as part of the Corporate Reorganization. Total consideration transferred in the exchange of Class B Units for common units was $302.7 million. All unrecognized compensation costs were expensed upon the vesting of the Class B Units. As of December 31, 2025, there was no unrecognized compensation cost related to incentive units.

10. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions including, but not limited to, title disputes, royalty disputes, contract claims, personal injury claims and employment claims. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. Nevertheless, actual outcomes may differ significantly from the Company's assessment. The Company recognized $8.2 million of expense pertaining to these matters during the second quarter of 2025 and it is presented in other income (expense), net in the statement of operations for the year ended December 31, 2025. As of December 31, 2025 the Company has no amounts accrued pertaining to these matters. As of December 31, 2024, the Company had accrued approximately $1.5 million in accrued liabilities pertaining to these matters. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

NGL Sales and Gas Transportation Commitments. The Company is party to a NGL sales contract, which includes certain NGL volume commitments in the event the Company elects not to reduce its committed quantity, at its option. To the extent the Company does not deliver NGL volumes in sufficient quantities to meet the commitment and does not elect to reduce its committed quantity, it would be required to pay a deficiency fee. The Company is currently delivering at least the minimum volumes. For the years ended December 31, 2025, 2024 and 2023, the Company incurred approximately $0.4 million, $3.4 million and $1.0 million, respectively, of transportation charges under these agreements. As of December 31, 2025, the Company has no material amounts remaining under these agreements.

Future Firm Sales Commitments. As part of the IKAV Acquisition, the Company is now party to a firm sales contract to deliver and sell a certain amount of natural gas at a fixed price of $1.72 per MMbtu through 2030. The Company expects to fulfill its delivery commitments primarily with production from proved developed reserves. The Company's production has been sufficient to satisfy its delivery commitments during the periods presented, and it expects its future production will continue to be the primary means of fulfilling its future commitments. However, if the Company's production is not sufficient to satisfy its delivery commitments, it can and may use spot market purchases to satisfy the commitments.

A summary of these volume commitments as of December 31, 2025 is set forth in the table below (in MMbtu):

	December 31, 2025
2026	70,338,571
2027	64,546,373
2028	59,621,628
2029	54,810,356
2030	50,753,106
Total	300,070,034

Contributions to 401(k) Plan. The Company sponsors a 401(k) plan under which eligible employees may contribute a portion of their total compensation up to the maximum pre-tax threshold through salary deferrals. The plan provides a company match on 100% of salary deferrals that do not exceed 10% of compensation. The Company contributed $5.0 million, $3.7 million and $1.7 million for the years ended December 31, 2025, 2024 and 2023, respectively.

11. Leases

Nature of Leases

The Company has operating leases on office spaces, various vehicles and compressors with remaining lease durations in excess of one year. These leases have various expiration dates through 2030. The vehicles are used for field operations and leased from third parties. The Company recognizes right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

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

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

2026	$	8,046
2027		6,686
2028		4,475
2029		2,342
2030		534
Total lease payments		22,083
Less: imputed interest		(2,532)
Total	$	19,551

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the years ended December 31, 2025, 2024 and 2023 (in thousands):

	Year ended December 31,					
	2025		2024		2023	
Operating lease cost	$	8,283	$	11,748	$	14,309

The Company does not have any material leases that are short term. The weighted-average remaining lease term as of December 31, 2025 was 3.16 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2025 was 7.82%.

	Year ended December 31,					
	2025		2024		2023	
Operating cash outflows from operating leases	$	7,955	$	11,681	$	14,066

12. Partners' Capital and Members' Equity

Partners' Capital

The Company was formed to effectuate the Corporate Reorganization, the Offering and related transactions thereto, as described in Note 1. Nature of Business. On October 25, 2023, the Company issued 88.8 million common units to Existing Owners of the Mach Companies. See Note 3 for additional information on the merger transactions related to the acquisitions of BCE-Mach and BCE-Mach II. On October 27, 2023, the Company completed the Offering and issued 10.0 million common units to public unitholders. Contemporaneously, the Company used a portion of the proceeds from the Offering to repurchase 3.8 million common units from certain Existing Owners of the Mach Companies.

On September 16, 2025, the Company closed the IKAV Acquisition and Sabinal Acquisition, which included the issuance of 30.6 million and 19.2 million common units, respectively, as part of the total consideration for each transaction. As of

September 15, 2025, the IKAV Unit Consideration and the Sabinal Unit Consideration had a value of approximately $409.9 million and $256.9 million, respectively.

On February 7, 2025, the Company completed a public offering of 12.9 million common units at a price to the public of $15.50 per common unit, less underwriting discounts and commissions (the “February 2025 Offering”). On February 12, 2025, the underwriters of the public offering fully exercised their option to purchase an additional 1.9 million common units at a price to the public of $15.50 per common unit, less underwriting discounts and commissions. The sale of the Company’s common units resulted in gross proceeds of $230.0 million and net proceeds of $221.1 million, after deducting underwriting fees and offering expenses. Proceeds from the offering were used to repay a portion of the Term Loan Credit Agreement and Revolving Credit Agreement.

On September 9, 2024, the Company completed a public offering of 7.3 million common units at a price of $16.50 per common unit. On September 24, 2024, the underwriters of the public offering partially exercised their option to purchase an additional 1.0 million common units at a price to the public of $16.50 per common unit, less underwriting discounts and commissions. The sale of the Company’s common units resulted in gross proceeds of $136.8 million and net proceeds of $128.9 million, after deducting underwriting fees and offering expenses. Proceeds from the offering were used to fund the Western Kansas Acquisition and the Ardmore Basin Acquisition.

As of December 31, 2025 and December 31, 2024, the Company had 168.4 million and 103.5 million common units outstanding, respectively. On February 7, 2026, 0.2 million common units were cancelled as part of post closing adjustments associated with the Sabinal Acquisition, which reduced total reported units outstanding on the Statement of Partners’ Capital as of December 31, 2025. As of December 31, 2025 there was 49.6 million units outstanding that were issued as part of the IKAV and Sabinal Acquisitions that were restricted by a 180-day lockup period.

For the years ended December 31, 2025 and 2024, the Company distributed $1.94 and $3.20 per unit, respectively, for total cash distributions of $244.5 million and $309.8 million, respectively.

Members’ Equity

Members’ equity of the Predecessor initially consisted of a single class of common interests, that were all owned by BCE-Mach Intermediate Holdings III LLC. On March 25, 2021, per the Predecessor’s amended and restated LLC agreement and the Class A-2 Issuance Agreement, the Predecessor issued 150,000 Class A-1 Units to its initial member, and 1,349 Class A-2 Units to an employee of Mach Resources for services performed for the Predecessor. Additional Class A-2 Units were granted to the employee on a quarterly basis throughout 2021 for a total of 3,504 Class A-2 Units granted, which have substantially all the same rights as the initial member. As part of a long-term incentive plan for certain employees, 20,000 Class B Units were issued and outstanding as of December 31, 2023. The Class B Units represented a non-voting interest in the Company that allowed the holder to participate in distributions once the Predecessor’s Class A units met a certain requisite financial internal rate of return in accordance with the Predecessor’s LLC agreement. See Note 9 for additional information on equity grants by the Predecessor. All of the equity interests in the Predecessor were exchanged for common units of the Company as part of the Corporate Reorganization.

Contributions from the Company’s predecessor members were $20.0 million for the year ended December 31, 2023. Distributions to the Company’s predecessor members were $101.4 million for the years ended December 31, 2023.

13. Earnings Per Common Unit

The Company has a single class of common units. The Company has potentially dilutive securities as of December 31, 2025, which consist of phantom units issued under the Company’s long-term incentive plan. The treasury stock method is used to determine the dilutive impact for the Company’s phantom units. As of December 31, 2025, 2024 and 2023, there were 29.8 thousand, 10.4 thousand and 0.7 million phantom units, respectively, that were considered antidilutive and thus excluded from the calculation of diluted earnings per common unit.

The following represents the computation of basic and diluted earnings per common unit for the years ended December 31, 2025, 2024 and 2023 (in thousands, except per unit data):

	Year Ended December 31,		
	2025	2024	2023
Net income - basic and diluted	$ 142,984	$ 185,179	$ 68,518
Weighted-average common units outstanding - basic	131,455	97,591	94,907
Effect of dilutive securities	82	110	—
Weighted-average common units outstanding - diluted	131,537	97,701	94,907
Earnings per common unit - basic	$ 1.09	$ 1.90	$ 0.72
Earnings per common unit - diluted	$ 1.09	$ 1.90	$ 0.72

14. Related Party Transactions

Management Services Agreement

On October 27, 2023, in connection with the closing of the Offering, the Company entered into a new management services agreement (the “MSA,” and together with the Predecessor MSA, the “MSAs”) with Mach Resources and terminated the Predecessor MSA. Under the MSAs, Mach Resources manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company and (i) will pay Mach Resources an annual management fee of approximately $7.4 million and (ii) reimburse Mach Resources for the costs and expenses of the services provided. On a monthly basis, the Company distributes funding to Mach Resources for performance under the MSA. During the years ended December 31, 2025, 2024 and 2023, the Company paid Mach Resources $135.7 million (inclusive of $7.4 million in management fees presented as general and administrative expense - related party in the statement of operations), $112.9 million (inclusive of $7.4 million in management fees presented as general and administrative expense - related party in the statement of operations) and $52.3 million (inclusive of $4.8 million in management fees presented as general and administrative expense - related party in the statement of operations), respectively. As of December 31, 2025 and 2024, the Company owed $0.9 million and $2.0 million, respectively, to Mach Resources, presented as accounts payable - related party.

Transition Services Agreements

In connection with the closing of the IKAV and Sabinal Acquisitions, the Company entered into a transition services agreement with each respective counterparty. For the year ended December 31, 2025, the Company paid the IKAV Sellers and the Sabinal Sellers $1.6 million and $4.3 million, respectively for continued assistance in transitioning processes to the Company.

Common units purchased by BCE-Mach Aggregator

In connection with the February 2025 Offering, BCE-Mach Aggregator, an affiliate of our General Partner, purchased 5,161,290 common units at the public offering price, which accounted for $79.2 million of the net proceeds received by the Company in the February 2025 Offering, after deducting underwriting fees. In connection therewith, the underwriters received a reduced underwriting discount on such common units purchased by BCE-Mach Aggregator compared to other common units sold to the public in the February 2025 Offering.

BCE-Mach and BCE-Mach II

BCE-Mach and BCE-Mach II were two related parties that previously entered into a MSA with Mach Resources. These entities had shared ownership, but were not under common control, with the Company prior to the Corporate Reorganization on October 25, 2023. See Note 1 and Note 3 for further discussion of the transactions involving these entities. As of December 31, 2023 and for periods subsequent to the Corporate Reorganization, all account balances and activities between the Company and these entities have been eliminated as intercompany transactions.

15. Segment Information

Management has evaluated that the Company is organized and managed as a single reportable segment, which is the exploration and production of oil, natural gas and NGLs (“E&P Segment”). All of the Company’s operations and assets are located in the United States, and its revenues are attributable to United States customers.

The accounting policies of the E&P Segment are the same as those described in Note 2.

The Company’s chief operating decision maker (“CODM”) is the Chief Executive Officer and Director. The CODM uses consolidated net income as presented on the accompanying statements of operations to measure E&P Segment profit or loss, and to evaluate income generated from E&P Segment assets in deciding whether to reinvest profits into operational activities or to use profits for other purposes, such as debt reduction, acquisitions, or distributions to unitholders. Additionally, consolidated net income is used in assessing budget versus actual results and in benchmarking to the Company’s competitors.

The following table summarizes total revenues, significant expenses, net income, total assets and capital expenditures related to the E&P Segment for time periods presented below (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Total revenues	$ 1,175,390	$ 969,628	$ 762,309
Gathering and processing	138,836	106,152	39,449
Lease operating expense	263,793	180,513	127,602
Production taxes	48,761	45,674	31,882
Total significant expenses	451,390	332,339	198,933
Midstream operating expense	13,319	10,466	10,873
Cost of product sales	25,901	24,026	28,089
Depreciation, depletion, amortization and accretion – oil and natural gas	280,459	261,949	131,145
Depreciation and amortization – other	12,305	9,018	6,472
General and administrative	49,236	33,438	22,861
General and administrative – related party	7,400	7,400	4,792
Impairment of oil and gas properties	90,430	—	—
Interest expense	72,219	104,596	11,201
Loss on debt extinguishment	18,540	—	—
Other expense, net	11,207	1,217	1,385
Total expenses	1,032,406	784,449	415,751
Net income	$ 142,984	$ 185,179	$ 346,558
Total assets	$ 3,777,308	$ 2,338,214	$ 887,858
Capital expenditures, including acquisitions	$ 1,570,276	$ 365,485	$ 1,077,686

16. Subsequent Events

Distribution Declaration

On February 12, 2026, the Company declared its quarterly distribution for the fourth quarter of 2025 of $0.53 per common unit, which will be paid on March 12, 2026.

The Company has evaluated subsequent events through the date of issuance of these financial statements to ensure that any subsequent events that met the criteria for recognition and disclosure in this Annual Report have been properly included.

17. Supplementary Financial Information for Oil and Gas Producing Activities (*Unaudited*)

The following tables provide historical cost information regarding the Company's oil and gas operations located entirely in the United States:

Capitalized Costs related to Oil and Gas Producing Activities

	As of December 31,	
(in thousands)	2025	2024
Proved properties	$ 4,017,896	$ 2,419,998
Accumulated depreciation, depletion, amortization and impairment	(879,253)	(520,641)
Net capitalized costs	$ 3,138,643	$ 1,899,357

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	Year Ended December 31,		
(in thousands)	2025	2024	2023
Acquisition	$ 1,210,871	$ 123,066	$ 774,887
Development	243,550	229,352	290,371
Exploratory	—	—	—
Costs incurred	$ 1,454,421	$ 352,418	$ 1,065,258

Results of Operations for Producing Activities

The following table includes revenue and expenses related to the production and sale of oil, natural gas, and NGLs. It does not include any derivative activity, interest costs or general and administrative costs.

	Year Ended December 31,		
(in thousands)	2025	2024	2023
Revenues	$ 1,037,650	$ 936,785	$ 647,352
Production costs	(451,390)	(332,339)	(198,933)
Depreciation, depletion, amortization and accretion	(280,459)	(261,949)	(131,145)
Impairment of oil and gas properties	(90,430)	—	—
Results of operations from producing activities	$ 215,371	$ 342,497	$ 317,274

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved undeveloped reserves or PUDs. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the US GAAP. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired. See Note 2 for additional information related to asset retirement obligations.

The standardized measure does not represent management's estimate of our future cash flows or the fair value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as affected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves Summary

All of the Company's reserves are located in the United States. The following table sets forth the changes in the Company's net proved reserves (including developed and undeveloped reserves) for the years ended December 31, 2025, 2024 and 2023. Reserves estimates as of December 31, 2025 were estimated by our independent petroleum consulting firms Cawley, Gillespie & Associates, Inc and Netherland, Sewell & Associates, Inc. Reserve estimates as of December 31, 2024 and prior were estimated by Cawley, Gillespie & Associates, Inc.

Proved Reserves	**Oil (MBbl)**	**Natural Gas (MMcf)**	**NGL (MBbl)**	**Oil Equivalents (MBoe)**
December 31, 2022	48,580	629,620	46,833	200,349
Revisions of previous estimates	(724)	(95,817)	(13,768)	(30,462)
Purchases in place	33,198	632,049	55,668	194,208
Extensions, discoveries and other additions	—	—	—	—
Sales in place	(36)	—	—	(36)
Production	(5,445)	(59,378)	(3,068)	(18,409)
December 31, 2023	75,573	1,106,474	85,665	345,650
Revisions of previous estimates	(5,762)	39,892	8,518	9,404
Purchases in place	5,015	26,783	4,456	13,934
Extensions, discoveries and other additions	—	—	—	—
Sales in place	(9)	—	—	(9)
Production	(7,382)	(101,147)	(7,489)	(31,729)
December 31, 2024	67,435	1,072,002	91,150	337,250
Revisions of previous estimates	(8,210)	199,215	7,241	32,234
Purchases in place	52,692	1,773,560	24,691	372,979
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(7,719)	(135,026)	(7,507)	(37,730)
December 31, 2025	104,198	2,909,751	115,575	704,732

Proved Developed Reserves	**Oil (MBbl)**	**Natural Gas (MMcf)**	**NGL (MBbl)**	**Oil Equivalents (MBoe)**
December 31, 2022	29,984	527,369	39,239	157,117
December 31, 2023	49,629	909,372	69,193	270,384
December 31, 2024	46,056	808,820	66,772	247,630
December 31, 2025	90,869	2,176,382	90,793	544,392

Proved Undeveloped Reserves	**Oil (MBbl)**	**Natural Gas (MMcf)**	**NGL (MBbl)**	**Oil Equivalents (MBoe)**
December 31, 2022	18,596	102,251	7,594	43,232
December 31, 2023	25,944	197,102	16,472	75,266
December 31, 2024	21,379	263,182	24,378	89,620
December 31, 2025	13,329	733,369	24,782	160,340

In 2023, the 194,208 MBoe of acquisitions represents the reserves acquired from several acquisitions that closed in 2023. See Note 3 for more information. The 30,462 MBoe of downward revisions in proved reserves were the result of lower commodity prices (-20,408 MBoe), the addition of PUDs within proven areas of development (23,014 MBoe), the deletion of PUDs due to changes in the corporate development plan (-36,762 MBoe) and the addition of proved developed producing reserves associated with the drilling of wells within proved areas that were not booked as PUD at prior year-end (8,672 MBoe). The remainder was associated with revisions to reflect current lease operating expenses and production pricing differentials.

In 2024, the 13,934 MBoe of acquisitions represents the reserves acquired from several acquisitions that closed in 2024. See Note 3 for more information. The 9,404 MBoe of upward revisions in proved reserves were the result of lower commodity prices (-16,859 MBoe), the addition of PUDs within proven areas of development (25,385 MBoe) and the addition of proved developed producing reserves associated with the drilling of wells within proved areas that were not booked as PUD at prior year-end (1,431 MBoe). The remainder was associated with revisions to reflect current lease operating expenses and production pricing differentials.

In 2025, the 372,979 MBoe of acquisitions represents the reserves acquired from several acquisitions that closed in 2025. See Note 3 for more information. The 32,234 MBoe of upward revisions in proved reserves were the result of higher commodity prices (25,847 MBoe), the addition of PUDs within proven areas of development (21,081 MBoe), the deletion of PUDs due to changes in the corporate development plan (-19,075 MBoe) and the addition of proved developed producing reserves associated with the drilling of wells within proved areas that were not booked as PUD at prior year-end (9,576 MBoe). The Company classifies these changes as revisions of previous estimates due to the Company’s drilling occurring in mature basins with well-established production histories and clearly defined development patterns, which we consider to be proven areas. The Company had no extensions or discoveries in 2025. The remainder was associated with revisions to reflect current lease operating expenses and production pricing differentials.

The following table sets forth the standardized measure of discounted future net cash flow from projected production of the Company's oil and natural gas reserves:

Standardized Measure of Discounted Future Net Cash Flows (in thousands)	As of December 31, 2025	2024	2023
Future cash inflows	$ 15,144,885	$ 8,120,568	$ 9,729,149
Future costs:			
Production[(1)]	(7,113,445)	(3,489,856)	(3,831,083)
Development[(2)]	(1,897,458)	(1,150,411)	(1,097,667)
Income taxes[(3)]	(17,761)	(1,099)	(1,773)
Future net cash flows	6,116,221	3,479,202	4,798,626
10% annual discount	(3,036,223)	(1,589,447)	(2,222,818)
Standardized measure	$ 3,079,998	$ 1,889,755	$ 2,575,808

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(1) Production costs include production severance taxes, ad valorem taxes and operating expenses.
(2) Development costs include plugging expenses, net of salvage and net capital investment.
(3) Represents Texas franchise tax.

Changes in Standardized Measure of Discounted Future Net Cash Flows (in thousands)	Year Ended December 31, 2025	2024	2023
Standardized measure, beginning of period	$ 1,889,755	$ 2,575,808	$ 2,951,627
Revisions of previous quantity estimates	209,397	72,769	(509,130)
Changes in estimated future development costs	(34,703)	(91,198)	4,361
Purchases of minerals in place	1,496,037	111,481	1,374,144
Net changes in prices and production costs	18,371	(536,970)	(1,248,485)
Divestiture of reserves	—	(295)	(1,207)
Accretion of discount	189,036	257,686	295,351
Net change in taxes	(7,413)	443	827
Sales of oil and gas produced, net of production costs	(586,260)	(604,446)	(448,419)
Development costs incurred during the period	76,192	168,617	56,064
Change in timing of estimated future production and other	(170,414)	(64,140)	100,675
Standardized measure, end of period	$ 3,079,998	$ 1,889,755	$ 2,575,808

Price and cost revisions are primarily the net result of changes in prices, based on beginning of the year reserve estimates. Future development costs revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Average oil prices used in the estimation of proved reserves and calculation of the standardized measure were $65.34, $75.48 and $78.22 for the years ended December 31, 2025, 2024 and 2023, respectively. Average realized gas prices were $3.39, $2.13 and $2.64 for the years ended December 31, 2025, 2024 and 2023, respectively. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

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

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(b) under the Exchange Act) as of December 31, 2025. Based on such evaluation, such officers have concluded that, as of December 31, 2025, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting (as defined by Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2025, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Control over Financial Reporting

Management, including the principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP.

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2025, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management believes that the Company's internal control over financial reporting was effective as of December 31, 2025.

Item 9B. Other Information

Not applicable.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Mach Natural Resources

We are managed and operated by our general partner, which is managed by the Board and executive officers of our general partner. The members of our general partner are BCE-Mach Aggregator, which is controlled by our Sponsor, and Mach Resources, which is controlled by Tom L. Ward. Our unitholders are not entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. Our general partner owes certain contractual duties to us as well as to its owners.

Our general partner has five directors, each of whom have been appointed by the Sponsor and Tom L. Ward through his ownership of Mach Resources, as the member of our general partner. The NYSE does not require a listed publicly traded limited partnership, such as ours, to have a majority of independent directors on the Board or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following consummation of this offering.

Our operations are conducted through, and our assets are owned by, various subsidiaries. However, we do not have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by third parties, such as pursuant to the MSA, but we sometimes refer to these individuals, for drafting convenience only, as our employees because they provide services directly to us.

The management, maintenance and operational functions of our business are currently provided by Mach Resources pursuant to the MSA. The MSA provides that we will reimburse Mach Resources for the direct and indirect costs associated with such services and pay an annual management fee of approximately $7.4 million. Neither our general partner directly nor the Sponsor currently receive any management fee or other compensation with respect to the management of our business; however, to the extent they did provide services in the future, they would be entitled to reimbursement under the partnership agreement. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. These expenses include salary, benefits, bonus, long term incentives and other amounts paid to persons who perform services for us or on our behalf.

In evaluating director candidates, our general partner assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board’s ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the Board to fulfill their duties.

Executive Officers and Directors of Our General Partner

The following table sets forth certain information regarding the current executive officers and directors of our general partner.

Name	Age	Position
Tom L. Ward	66	Chief Executive Officer and Director
Kevin R. White	68	Chief Financial Officer
Michael E. Reel	40	General Counsel and Secretary
William W. McMullen	40	Chairman of the Board
Edgar R. Giesinger	69	Director
Stephen Perich	46	Director
Christopher J. Burn	60	Director

Tom L. Ward — Chief Executive Officer and Director. Mr. Ward has served as our Chief Executive Officer since our founding in 2017 and as a Director since the Offering. Prior to joining the Company, he served as Chairman and Chief Executive Officer of Tapstone Energy from 2013 to 2017 and Sandridge Energy (NYSE: SD) from 2006 to 2013. Prior to joining SandRidge Energy, he served as President, Chief Operating Officer and a director of Chesapeake Energy

Corporation (NYSE: CHK) from the time he co-founded the company in 1989 until February 2006. Mr. Ward graduated from the University of Oklahoma in 1981 with a Bachelor of Business Administration in Petroleum Land Management.

We believe that Mr. Ward's extensive industry background, his previous experience as a director and executive of public companies, and deep knowledge of our business as founder make him well suited to serve as a member of our board of directors.

Kevin R. White — Chief Financial Officer. Mr. White has served as our Chief Financial Officer since March 2017. Prior to joining the Company, he served as Chief Financial Officer of Petroflow Energy Corporation from June 2016 to March 2017 and as SVP — Business Development and Investor Relations of SandRidge Energy from January 2008 to September 2013. Mr. White served as Executive Vice President of Corporate Development and Strategic Planning for Louis Dreyfus Natural Gas Corp. from 1993 until the company was sold in 2001. He attended Oklahoma State University, receiving his Bachelor of Science degree in Accounting in 1979 and a Master of Science degree in Accounting and his Certified Public Accountant qualification in 1980.

Michael E. Reel — General Counsel and Secretary. Mr. Reel joined the Company in July 2017 and currently serves as General Counsel and Secretary. Prior to joining the Company, he served as Senior Counsel for Accelerate Resources. Prior to his time at Accelerate Resources, Mr. Reel served as internal counsel for White Star Petroleum, LLC, American Energy Partners, LP and Chesapeake Energy Corporation. Mr. Reel graduated from Oklahoma State University in 2008 with a Bachelor of Science degree in Political Science and received his Juris Doctorate from Oklahoma City University School of Law in 2011.

William W. McMullen — Chairman of the Board. Mr. McMullen has served as Chairman of the Board since the Offering, and as Founder and Managing Partner of BCE since 2015, leading the firm's investment strategy and capital allocation decisions. Prior to founding BCE in 2015, Mr. McMullen worked at White Deer Energy from 2012 to 2014. Previously, Mr. McMullen worked at Denham Capital Management from 2010 to 2012 and UBS Investment Bank's Global Energy Group from 2008 to 2010. Mr. McMullen earned his AB in Economics, with Honors, from Harvard University.

We believe that Mr. McMullen's industry experience, his previous leadership positions and finance-related roles, as well as his deep knowledge of our business, make him well suited to serve as a member of our board of directors.

Edgar R. Giesinger — Director. Mr. Giesinger has served as a Director since the Offering. Mr. Giesinger retired as a managing partner from KPMG LLP in 2015. Since November 2015, Mr. Giesinger has served on the board of directors of Geospace Technologies Corporation (NASDAQ: GEOS), a publicly traded company primarily involved in the design and manufacture of instruments and equipment utilized in oil and gas industries. Since May 2017, Mr. Giesinger has served on the board of directors of Solaris Energy Infrastructure, Inc. (NYSE: SEI), a public company that delivers power generation and distribution solutions, and logistics equipment and services, serving clients in the data center, energy, and other commercial and industrial sectors. He has 35 years of accounting and finance experience working mainly with publicly traded corporations. Over the years, he has advised a number of clients in accounting and financial matters, capital raising, international expansions and in dealings with the SEC. While working with companies in a variety of industries, his primary focus has been energy and manufacturing clients. Mr. Giesinger is a certified public accountant in the State of Texas and former chairman of the Texas TriCities Chapter of the National Association of Corporate Directors. He has lectured and led seminars on various topics dealing with financial risks, controls and financial reporting. Mr. Giesinger graduated from the University of Texas with a Bachelor of Business Administration in Accounting.

We believe that Mr. Giesinger's extensive financial and accounting experience, including that related to the energy and manufacturing industries, qualifies him to effectively serve as a member of the Board.

Stephen Perich — Director. Mr. Perich has served as a Director since the Offering. Mr. Perich served as the Head of Energy Investment Banking for the Americas at UBS Investment Bank from August 2018 to November 2023. As head of UBS' energy investment banking practice, he managed a team of professionals focused on capital markets execution and mergers and acquisitions advisory services. He maintained regular strategic dialogue with management teams and boards of directors of energy companies, assisting them with capital raising and strategic growth initiatives. Since January 2024, he has served on the Board of Directors of Visuray PLC, an oilfield technology company. He has lectured and led conferences on various topics including energy fundamentals and capital markets. Mr. Perich graduated from Georgetown University in 2001 with a Bachelor of Science degree in Finance and received a Master of Business Administration from the University of Texas at Austin in 2006.

We believe that Mr. Perich's extensive experience in financial markets, oil and gas, capital markets and mergers and acquisitions, including that related to the energy and manufacturing industries, qualifies him to effectively serve as a member of the Board.

Christopher J. Burn — Director. On December 15th, 2025, Mr. Burn was appointed as Director. Since July 2025, Mr. Burn has served as a consultant at Goshen Analytics LLC, formerly Goshen Investments, LLC. Mr. Burn previously served as the Chief Investment Officer of The Diana Davis Spencer Foundation from November 2021 to June 2025, again as a consultant at Goshen Investments, LLC from May 2021 to October 2021 and as Global Head of Macro Research of Archegos Capital Management from 2018 to March 2021. Mr. Burn graduated from Wesleyan University in 1988 with a Bachelor of Arts from the College of Social Studies and received a Master of Business Administration from the Wharton School at the University of Pennsylvania in 1995.

We believe that Mr. Burn's extensive experience in financial markets and previous leadership positions in finance-related roles, qualifies him to effectively serve as a member of our board of directors.

Francis A. Keating II — Ex-Director. On December 15, 2025, Mr. Keating resigned, effective immediately, as a director of the board of directors of Mach Natural Resources GP LLC, and as a member of the Audit Committee and the Conflicts Committee. Mr. Keating's resignation was not because of any disagreement with management or the board of directors on any matter relating to the Partnership's operations, policies or practices.

Board of Directors

Our general partner has a five-member board of directors. The members of our general partner are (i) BCE-Mach Aggregator, the majority of the membership interests of which are owned by investment funds managed by Bayou City Energy Management LLC and its affiliates, and (ii) Mach Resources, which is controlled by Tom L. Ward, with such membership interests and Board appointment rights of such members held in proportion to their respective limited partnership interest ownership in us. Such proportional membership interest of Tom L. Ward includes certain ownership of trusts affiliated with Mr. Ward, which such membership interests currently represent approximately 1.7% of our outstanding common units. Specifically, each of BCE-Mach Aggregator and Mach Resources shall separately be entitled to appoint (i) one director if its membership interests are greater than 0% but equal to or less than 25%, (ii) two directors if its membership interests are greater than 25% but equal to or less than 50%, (iii) three directors if its membership interests are greater than 50% but equal to or less than 75%, (iv) four directors if its membership interests are greater than 75% but less than 100% and (v) five directors if its membership interests are 100%. Further, to the extent each of BCE-Mach Aggregator and Mach Resources are entitled to appoint a director, each shall only be entitled to appoint one director that is not Independent (as defined in the general partner agreement). As a result, the Sponsor controls our general partner and is entitled to appoint four members of the Board and Mach Resources is entitled to appoint one member of the Board.

In evaluating director candidates, sole members of our general partner assessed whether a candidate possessed the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the Board to fulfill their duties.

Our general partner's directors hold office until the earlier of their death, resignation, retirement, disqualification or removal or until their successors have been duly elected and qualified.

Additionally, pursuant to the general partner agreement, the Board has the right by delivery of written notice to BCE-Mach Aggregator and Mach Resources to require the Company, the Board and BCE-Mach Aggregator and Mach Resources, to take all necessary action to transfer all of the outstanding membership interests of our general partner to the Company for no additional consideration and amend our partnership agreement to provide the holders of common units with voting rights in the election of the members of the Board, as the general partner of the Company.

Director Independence

Our independent directors, William W. McMullen, Edgar R. Giesinger, Stephen Perich and Christopher J. Burn, meet the independence standards established by the NYSE listing rules.

Code of Business Conduct and Ethics

Our Board of Directors has adopted a Code of Ethics, which is available free of charge on our website, ir.machnr.com. We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Ethics by posting such information on the website address and location specified above.

Insider Trading Policy

The Company has adopted and maintains the Insider Trading Policy (the “Insider Trading Policy”), which the Company believes is reasonably designed to promote compliance with federal and state securities laws, rules and regulations, and NYSE listing standards. The Insider Trading Policy applies to all directors, officers, and employees of the Company and its subsidiaries, any other person or entity determined by our general partner who have access to material nonpublic information, such as contractors and consultants, as well as to Company and our general partner. It governs the purchase, sale, or other disposition of the Company’s securities, other equity investments, and derivative securities (e.g., common units, options to purchase common units, common unit appreciation rights, restricted units, phantom units, and derivative securities that are not issued by the Company, such as exchange-traded put or call options or swaps relating to Company’s securities) and generally prohibits, among other things, persons subject to the Insider Trading Policy from engaging in transactions in the Company’s securities while aware of material, non-public information relating to the Company or its securities.

Committees of the Board of Directors

The Board has an audit committee, a compensation committee, and a conflicts committee. The NYSE listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee. However, we have established a compensation committee that has the responsibilities set forth below.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE listing rules and rules of the SEC. The audit committee assists the Board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management. Edgar R. Giesinger, Stephen Perich and Christopher J. Burn serve on the audit committee. Edgar R. Giesinger serves as chair of the audit committee. SEC rules also require that a public company disclose whether its audit committee has an “audit committee financial expert” as a member. The Board has determined that Edgar R. Giesinger qualifies as an “audit committee financial expert,” as such term is defined in Item 407(d) of Regulation S-K.

Conflicts Committee

In accordance with the terms of our partnership agreement, two or more members of the Board serve on our conflicts committee to review specific matters that may involve conflicts of interest. The members of our conflicts committee cannot be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on a conflicts committee of a board of directors. In addition, the members of our conflicts committee cannot own any interest in our general partner or its affiliates or any interest in us or our subsidiaries other than common units or awards, if any, under our incentive compensation plan. Edgar R. Giesinger, Stephen Perich and Christopher J. Burn serve as members of our conflicts committee.

Compensation Committee

The members of our compensation committee are Edgar R. Giesinger, Stephen Perich and William W. McMullen. Stephen Perich serves as chair of the compensation committee. Each of the members of our compensation committee are independent under the applicable rules and regulations of the NYSE and are a “non-employee director” as defined in Rule 16b-3 promulgated under the Exchange Act. The compensation committee operates under a written charter that satisfies the applicable standards of the SEC and the NYSE.

The compensation committee’s responsibilities include:

- annually reviewing and approving corporate goals and objectives relevant to compensation of our chief executive officer and our other executive officers;

- annually reviewing and making recommendations to our board of directors with respect to the compensation of our chief executive officer and determining the compensation for our other executive officers;
- reviewing and making recommendations to our board of directors with respect to director compensation; and
- overseeing and administering our equity incentive plans.

From time to time, our compensation committee may use outside compensation consultants to assist it in analyzing our compensation programs and in determining appropriate levels of compensation and benefits. The compensation committee will review and evaluate, at least annually, the performance of the compensation committee and its members, including compliance by the compensation committee with its charter.

Board Leadership Structure

Leadership of our general partner's board of directors is vested in a Chairman of the Board. Mr. William W. McMullen serves as a Director and the Chairman of the Board. We have no policy with respect to the separation of the offices of chairman of the Board and chief executive officer. Instead, that relationship is defined and governed by the general partner agreement of our general partner, which permits the same person to hold both offices. Directors of the Board are designated or elected by the Sponsor and Tom L. Ward through his ownership of Mach Resources as the members of our general partner. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our corporate governance guidelines provide that the Board is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility is largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our independent registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies**.**

Delinquent Section 16(a) Reports

None.

Item 11. Executive Compensation

We do not directly employ directors, officers or employees; instead, all of the employees that conduct our business are either employed by Mach Resources or its subsidiaries. We depend on Mach Resources and such employees to provide us and our General Partner with services necessary to operate our business. The management, maintenance and operational functions of our business are currently provided by Mach Resources pursuant to the MSA. The MSA provides that we will reimburse Mach Resources for the direct and indirect costs associated with such services and pay an annual management fee of approximately $7.4 million. Neither our General Partner nor the Sponsor currently receive any management fee or other compensation with respect to the management of our business; however, to the extent they did provide services in the future, they would be entitled to reimbursement under the partnership agreement. Our partnership agreement does not set a limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us. The reimbursement of expenses to our General Partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. During the year ended December 31, 2025, we paid $135.7 million to Mach Resources, which consists of $7.4 million for an annual management fee and $128.3 million for reimbursements of its costs and expenses under the MSA.

For a description of our other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions and Director Independence" included in Item 13 of Part III of this Annual Report. Although all of the employees that conduct our business are employed by Mach Resources, we sometimes refer to these individuals in this Annual Report as our employees.

Emerging Growth Company Status

We are currently considered an "emerging growth company," within the meaning of the Securities Act, for purposes of the SEC's executive compensation disclosure rules. Accordingly, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures regarding executive compensation for our last completed fiscal year. Furthermore, our reporting obligations extend only to our "named executive officers," who are the individuals who served as our principal executive officer during 2025 and our next two most highly compensated executive officers at the end of 2025. Accordingly, our "Named Executive Officers" for 2025 are:

Name	Principal Position
Tom L. Ward	Chief Executive Officer
Kevin R. White	Chief Financial Officer
Michael E. Reel	General Counsel and Secretary

2025 Summary Compensation Table

The following table summarizes the compensation awarded to, earned by or paid to our Named Executive Officers for the fiscal year ended December 31, 2025.

Name and Principal Position	Year	Salary[1]	Bonus[2]	Stock Awards[3]	Non-Equity Incentive Plan Compensation	All Other Compensation[4]	Total
Tom L. Ward	2025	$ 750,000	$ —	$ —	$ —	$ 537,262	$ 1,287,262
Chief Executive Officer	2024	$ 600,000	$ —	$ —	$ —	$ 457,771	$ 1,057,771
Kevin R. White	2025	$ 546,250	$ 332,312	$ 898,995	$ —	$ 153,775	$ 1,931,332
Chief Financial Officer	2024	$ 546,250	$ 72,625	$ 800,619	$ —	$ 90,089	$ 1,509,583
Michael E. Reel	2025	$ 384,532	$ 133,263	$ 351,005	$ —	$ 58,352	$ 927,152
General Counsel and Secretary	2024	$ 361,324	$ 44,533	$ 367,814	$ —	$ 31,027	$ 804,698

(1) The amounts in this column reflect the base salary earned by each Named Executive Officer.

(2) The amounts in this column represent discretionary short-term cash incentive awards paid as more specifically discussed under "Narrative Disclosure to Summary Compensation Table — Annual Bonuses." For Messrs. White and Reel, $18,000 and $8,500 of the 2024 amounts in the column, respectively, represent a separate, discretionary bonus awarded by the Board's compensation committee based on Company performance at 2024 year-end.

(3) Represents the grant date fair value of Performance Phantom Units (as defined below) granted to Messrs. White and Reel pursuant to the Long-Term Incentive Plan. The amounts shown in this column were computed in accordance with Financial Accounting Standards Board ("FASB") Accounting Standard Codification ("ASC") Topic 718. See Note 9 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report for details. These amounts do not necessarily correspond to the actual value that will be realized by Messrs. White and Reel.

(4) The amounts in this column reflect the Company's matching contributions to the Company's 401(k) plan for the Named Executive Officers for each year presented. For 2024, amounts include DER payments associated with the vesting of Award Units (as defined below) of $0.1 million, $60 thousand, and $16 thousand for Messrs. Ward, White and Reel, respectively. For 2025, amounts include DER payments associated with the vesting of Award Units of $0.2 million, $0.1 million, and $35 thousand for Messrs. Ward, White and Reel, respectively. For Mr. Ward, these amounts include personal use of chartered aircraft of $0.3 million for fiscal years ended December 31, 2025, and 2024, respectively.

Narrative Disclosure to Summary Compensation Table

No Employment Agreements and/or Offer Letters

We have not entered into any employment agreement, offer letter or similar employment contract with any of our Named Executive Officers.

Base Salary

Each Named Executive Officer's base salary is a fixed component of compensation for performing specific job duties and functions. Base salaries are generally set at levels deemed necessary to attract and retain individuals with superior talent commensurate with their relative expertise and experience.

Annual Bonuses

Annual cash bonuses are used to motivate and reward our executives and other employees. The annual bonuses paid to our Named Executive Officers (other than Mr. Ward) are discretionary bonuses determined by Mr. Ward and the Compensation Committee, and not linked to any performance metrics of the Company or otherwise. Mr. Ward historically has not been considered for annual bonuses and, accordingly, Mr. Ward did not receive an annual bonus in 2025 or 2024. The Compensation Committee approved the following target annual bonus opportunities for each of our Named Executive Officers (other than Mr. Ward) effective January 1, 2025: $305,000 for Mr. White and $115,000 for Mr. Reel.

Equity Incentives

2023 Long-Term Incentive Plan

In connection with the consummation of the Offering, the Board adopted a long-term incentive plan (the "Long-Term Incentive Plan") in which our Named Executive Officers, employees, consultants and directors are eligible to participate. The Long-Term Incentive Plan provides for the grant of cash awards, options to purchase common units of the Company, unit appreciation rights, restricted units, phantom units ("Award Units"), unit awards, distribution equivalent rights ("DERs") and other unit-based awards intended to align the interests of service providers, including our Named Executive Officers, with those of our unitholders. The Long-Term Incentive Plan is filed herewith as Exhibit 10.1.

In connection with the consummation of the Offering, we granted certain time-based vesting awards ("Time-Based Phantom Units") under the Long-Term Incentive Plan. The Time-Based Phantom Units granted to our Named Executive Officers were comprised of Award Units, each of which was issued in tandem with a corresponding DER, which entitles the Named Executive Officer to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Time-Based Phantom Unit is outstanding. The Time-Based Phantom Units vest ratably on each of the first three anniversaries of the date of grant, subject to the Named Executive Officer's continued employment through the applicable vesting date, and a Time-Based Phantom Unit's corresponding DER vests at the same time the Time-Based Phantom Unit vests. The Time-Based Phantom Units (and their corresponding DERs) held by the Named Executive Officers are subject to accelerated vesting in certain circumstances as discussed under "Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control."

The Company awarded a target number of performance-based Award Units ("Performance Phantom Units") to Messrs. White and Reel under the Long-Term Incentive Plan, as follows: (i) 31,758 and 52,328 to Mr. White in May 2024 and January 2025, respectively, and (ii) 14,590 and 20,431 to Mr. Reel in May 2024 and January 2025, respectively. The number of shares of common units issued pursuant to each Performance Phantom Unit award agreement will be from 0% to 200% of the target number of Performance Phantom Units thereunder based on a combination of the Company's (i) total shareholder return ("TSR"), (ii) relative total shareholder return ("RTSR") compared to the TSR of the companies in the Company's designated peer group, and (iii) total recordable incident rate ("TRIR"), in each case, for the applicable performance period. The Performance Phantom Unit awards are broken into two categories: long-term performance units (which constitute 50% of the target Performance Phantom Units subject to an award), which have a three year performance period, and short-term performance units (which constitute the remaining 50% of the target Performance Phantom Units subject to an award), which are broken into three substantially equal tranches with separate one-year performance periods. Performance Phantom Units vest based on the achievement of the applicable performance metrics at the end of the applicable performance period, subject generally to the applicable executive officer's continued employment through such performance period. Within 60 days following the vesting of a Performance Phantom Unit, the executive officer will receive a common unit of the Company. Each Performance Phantom Unit was granted with a corresponding DER. The Performance Phantom Units (and their corresponding DERs) held by the Named Executive Officers are subject to accelerated vesting in certain circumstances as discussed under "Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control."

Outstanding Equity Awards at 2025 Fiscal Year-End

The following table sets forth information regarding all outstanding equity incentive awards held by each of our Named Executive Officers as of December 31, 2025.

Name	Grant Date	Number of Units That Have Not Vested (#)[1]	Market Value of Units That Have Not Vested ($)[2]	Equity Incentive Plan Awards: Number of Unearned Units that have not Vested (#)[3]	Equity Incentive Plan Awards: Market Value of Unearned Units that have not Vested ($)[2]
Tom L. Ward	10/27/2023	36,842	$ 406,736	—	$ —
Kevin R. White	1/1/2025	—	$ —	43,606	$ 481,410
	5/3/2024	—	$ —	21,171	$ 233,728
	10/27/2023	22,918	$ 253,015	—	$ —
Michael E. Reel	1/1/2025	—	$ —	17,025	$ 187,956
	5/3/2024	—	$ —	9,726	$ 107,375
	10/27/2023	6,103	$ 67,377	—	$ —

(1) This columns represents Time-Based Phantom Units. Time-Based Phantom Units vest as described under “Narrative Disclosure to Summary Compensation Table — Equity Incentives.” Each Time-Based Phantom Unit was granted in tandem with a corresponding DER, which entitles the Named Executive Officer to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Time-Based Phantom Unit is outstanding. A Time-Based Phantom Unit’s corresponding DER vests at the same time the Time-Based Phantom Unit vests. The Time-Based Phantom Units (and their corresponding DERs) held by the Named Executive Officers are subject to accelerated vesting as discussed under “Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control.”

(2) The market value amounts in this table were calculated based on unit price of $11.04, the closing price of our common units on the New York Stock Exchange on December 31, 2025, the last trading day in fiscal year 2025.

(3) This column represents Performance Phantom Units. Performance Phantom Units vest as described under “Narrative Disclosure to Summary Compensation Table — Equity Incentives.” Each Performance Phantom Unit was granted in tandem with a corresponding DER, which entitles the Named Executive Officer to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Performance Phantom Unit is outstanding. A Performance Phantom Unit’s corresponding DER vests at the same time the Performance Phantom Unit vests. The Performance Phantom Units (and their corresponding DERs) held by the Named Executive Officers are subject to accelerated vesting as discussed under “Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control.” The one-year performance tranche for 2024 under the Performance Phantom Unit awards granted May 3, 2024 was earned at 93.75% based on 125% achievement of the TSR and RTSR performance components and 0% achievement of TRIR performance components, in each case, for 2024. The one-year performance tranches for 2025 under the Performance Phantom Unit awards granted May 3, 2024 and January 1, 2025 were earned at 0% based on a 0% achievement of the TSR and RTSR and a 0% achievement of the TRIR performance components, in each case, for 2025.

Additional Narrative Disclosure

Retirement Benefits

We do not have a defined benefit pension plan or nonqualified deferred compensation plan. We currently maintain a retirement plan intended to provide benefits under Section 401(k) of the Code, pursuant to which employees, including the Named Executive Officers, can make voluntary pre-tax contributions. We match 100% of elective deferrals up to 10% of salary for our Named Executive Officers. Our employer matching contributions vest in equal, annual installments on the first four anniversaries of a participant’s commencement of service, and our Named Executive Officers are 100% vested in employer matching contributions. All contributions under the retirement plan are subject to certain annual dollar limitations, which are periodically adjusted for changes in the cost of living.

Potential Payments Upon Termination or Change in Control

Executive Severance Plan

In May 2024, the Board adopted the Mach Natural Resources LP Executive Change in Control and Severance Plan (the “Executive Severance Plan”) and designated Mr. Ward as a “Tier 1 Executive” and each of Messrs. White and Reel as a “Tier 2 Executive” thereunder. Upon a Qualifying Termination that occurs outside of the period commencing on the date on which a “Change in Control” (as defined in the Long-Term Incentive Plan) is consummated and ending on the 12-month anniversary of the date on which such Change in Control is consummated (the “Change in Control Protection Period”), so long as the participating executive executes and does not revoke a general release of claims (the “Release Requirement”) and continues to abide by the restrictive covenants in the Executive Severance Plan, the participating executive will be entitled to receive (i) a cash severance payment equal to (a) for a Tier 1 Executive, such executive’s annual base salary, and (b) for a Tier 2 Executive, five weeks of such executive’s base salary for each full year of employment or service with the Company, the General Partner and each of their direct and indirect past, present and future subsidiaries (the “Partnership Group”), with a minimum of five weeks of such executive’s base salary and a maximum of fifty-two (52) weeks of such executive’s base salary, in each case, payable in a lump sum on the Company’s first regularly scheduled pay date on or after the date that is 60 days after such executive’s termination date, and (ii) any earned but unpaid annual bonus with respect to the calendar year ending on or preceding such executive’s termination, payable on the otherwise applicable payment date (the “Prior Year Bonus”).

Upon the Qualifying Termination of a participating executive that occurs during a Change of Control Protection Period, so long as the executive satisfies the Release Requirement and continues to abide by the restrictive covenants in the Executive Severance Plan, the participating executive will be entitled to receive (i) the Prior Year Bonus, and (ii) a cash severance payment equal to the sum of the following amounts, payable in a lump sum no later than 60 days after the executive’s date of termination: (a) an amount equal to the product of (I) 2.5 (for a Tier 1 Executive) or 1.5 (for a Tier 2 Executive) and (II) the sum of the executive’s (A) annual base salary and (B) target annual bonus, (b) a pro-rated portion of the executive’s target annual bonus, and (c) an amount equal to the product of (I) 12 and (II) the monthly amount of the Company’s contribution to the premiums for such executive’s group health plan coverage (including coverage for such executive’s spouse and eligible dependents). Outstanding equity incentive awards held by such participating executive would be treated in accordance with the terms and conditions of the applicable award agreement and, as applicable, the Long-Term Incentive Plan. The Executive Severance Plan generally supersedes the severance entitlements, if any, provided to any participating executives under any prior agreements, plans or arrangements.

Under the Executive Severance Plan, “Qualifying Termination” generally means the termination of a participating executive’s employment (i) by any member of the Partnership Group without Cause (as defined in the Long-Term Incentive Plana and summarized below), which does not include a termination due to death or disability, or (ii) due to a participating executive’s resignation for Good Reason.

Under the Severance Plan, “Good Reason” is generally defined to mean (subject to customary notice and cure provisions): (i) a material diminution in title, position or duties; (ii) a material reduction in base salary or target annual bonus opportunity (provided that a reduction in the base salary or target annual bonus opportunity that occurs in connection with an across-the-board base salary or target bonus opportunity reduction affecting all other members of the management team of the Company on a proportionate basis will not constitute Good Reason); (iii) relocation of the employee’s primary office location by more than 50 miles; or (iv) any material breach by the Company, the General Partner or one of their affiliates of the Executive Severance Plan.

Time-Based Phantom Unit Grant Agreements

Under the applicable Time-Based Phantom Unit grant agreements with each of the Named Executive Officers, if a Named Executive Officer is terminated by our General Partner or one of its affiliates (including the Company) without “Cause” (as defined below) or the Named Executive Officer resigns for “Good Reason” (as defined below) within the two-year period beginning on the occurrence of a “Change in Control” (as defined in the Long-Term Incentive Plan), then all unvested and outstanding Time-Based Phantom Unit (and all DERs corresponding to such Time-Based Phantom Unit) will vest in full as of such termination. In addition, the vesting of the Time-Based Phantom Unit may be accelerated in the discretion of the Board’s compensation committee within the 30 days following certain terminations of the Named Executive Officers.

Under the Long-Term Incentive Plan, “Cause” is generally defined to mean (subject to notice and cure provisions for clauses (iii), (iv) and (v)): (i) conviction of, or plea of guilty or *nolo contendere* to, any felony or any crime involving theft, embezzlement, dishonesty or moral turpitude; (ii) any act constituting theft, embezzlement, fraud or similar conduct in the performance of the employee’s duties with respect to the Company, the General Partner or one of their affiliates; (iii) any act constituting willful misconduct, deliberate malfeasance or gross negligence in the performance of the employee’s duties with respect to the Company, the General Partner or one of their affiliates; (iv) willful and continued failure to perform any of the employee’s duties; or (v) any material breach by the employee of the Long-Term Incentive Plan, any award agreement thereunder or any other agreement between the employee and the Company, the General Partner or one of their affiliates.

For purposes of the Time-Based Phantom Unit grant agreements with our Named Executive Officers, “Good Reason” is generally defined to mean (subject to customary notice and cure provisions): (i) a material diminution in title, position or duties; (ii) a material reduction in any component of the employee's compensation (provided that, for clarity, a reduction in the fair market value of any common units or other equity securities granted as compensation to the employee will not be considered to be a reduction in compensation); (iii) relocation of the employee's primary office location by more than 50 miles; or (iv) any material breach by the Company, the General Partner or one of their affiliates of any agreement between the employee, on the one hand, and the Company, the General Partner or one of their affiliates, on the other hand, in each case, unless mutually agreed in writing.

Performance Phantom Unit Grant Agreements

Under the applicable Performance Phantom Unit grant agreements with our Named Executive Officers, if a Named Executive Officer incurs a Qualifying Termination outside of a Change in Control Retention Period (as such terms are defined in the Executive Severance Plan and summarized above), subject to the Release Requirement, a pro-rata portion of the outstanding Performance Phantom Units may become earned as of the end of the applicable performance period. Such pro-rata portion will be equal to (A) the number of Performance Phantom Units that would have been earned at the end of the applicable performance period based on actual performance, multiplied by (B) a fraction, the numerator of which is the number of days in the applicable performance period that the Named Executive Officer remained in continuous employment or service with the Company, the General Partner or an any of their respective affiliates and the denominator of which is the number of days in the applicable performance period.

Upon a Change in Control, if the applicable Performance Phantom Unit grant agreement is not assumed by the successor or survivor entity, any outstanding and unearned Performance Phantom Units thereunder will be deemed earned (A) if the applicable performance period has commenced, at the greater of target performance and actual performance as of the effective date of the Change in Control (determined as though the applicable performance period ends early on the effective date of the Change in Control ("Actual Performance")), and (B) if the applicable performance period has not commenced, at target performance. If the applicable Performance Phantom Unit grant agreement is assumed by the successor or survivor entity in connection with a Change in Control, and the Named Executive Officer subsequently incurs a Qualifying Termination during the Change in Control Protection Period (as such terms are defined in the Executive Severance Plan and summarized above), any outstanding and unearned Performance Phantom Units will be deemed earned (A) if the applicable performance period has commenced as of the effective date of the Change in Control, at the greater of target performance and Actual Performance, and (B) if the applicable performance period has not commenced as of the effective date of the Change in Control, at target performance, in each case, subject to the Release Requirement.

Non-Employee Director Compensation

The Board has adopted a compensation program for our non-employee directors, or the "Non-Employee Director Compensation Policy." The Non-Employee Director Compensation Policy became effective as of October 27, 2023. Pursuant to the Non-Director Compensation Policy, each member of the Board who is not our employee will receive the following cash compensation for board services, as applicable:

a. $75,000 per year for service as a board member; and

b. an additional $25,000 per year for service as chairperson of the Audit Committee or Compensation Committee.

In September 2025, the Compensation committee approved an increase to $82,500 per year for service as a board member, effective as of January 1, 2026.

In addition, pursuant to the Non-Employee Director Compensation Policy, annually, on a date determined by the Board, each individual who serves as a non-employee director as of such date will receive grants of Award Units with a grant date value equal to approximately $150,000 and, for each such Award Unit, a corresponding DER, which entitles the director to receive a cash payment equal to the total distributions paid by the Company in respect of a common unit during the time the corresponding Award Unit is outstanding. The Award Units (and their corresponding DERs) will vest on the earlier of (i) the first anniversary of the date of grant and (ii) a Change in Control (as defined in the Long-Term Incentive Plan), in each case, subject to such director's continuing service on the Board through such date or Change in Control, as applicable. Our Non-Employee Director Compensation Policy provides that the Award Units and corresponding DERs will be granted under and will be subject to the terms and provisions of the Long-Term Incentive Plan and will be granted subject to the execution and delivery of award agreements.

Director Compensation Table

The following table summarizes the compensation awarded or paid to certain non-employee members of the Board for the fiscal year ended December 31, 2025. For summary information on the provision of the plans and programs, refer to the "Non-Employee Director Compensation" discussion immediately preceding this table.

Name	Fees Earned or Paid in Cash[1]	Stock Awards[2]	All Other Compensation[3]	Total
Edgar R. Giesinger	$ 100,000	$ 150,006	$ 20,839	$ 270,845
Stephen Perich	$ 100,000	$ 150,006	$ 20,839	$ 270,845
Francis A. Keating II	$ 75,000	$ 150,006	$ 20,839	$ 245,845
Christopher J. Burn	$ —	$ —	$ —	$ —
William W. McMullen[4]	$ —	$ —	$ —	$ —

(1) Represents fees earned by or paid to our non-employee directors for services during calendar year 2025.

(2) Each of our non-employee directors (other than Mr. McMullen) received an award of 12,039 Award Units, each of which was granted with a corresponding DER. The amounts reflected in this column represent the grant date fair value of the Award Units granted to each of our non-employee directors pursuant to the Long-Term Incentive Plan, as computed in accordance with FASB ASC Topic 718. See Note 9 of our audited consolidated financial statements included in Item 8 of Part II of this Annual Report for details.

(3) For Mr. Giesinger, Mr. Perich, and Mr. Keating, represents DER payments in connection with vesting of Award Units. Mr. McMullen does not receive any DER payments.

(4) Mr. McMullen does not receive cash or stock awards for his service as a member of the Board under the Non-Employee Director Compensation Policy because he is a service provider of Bayou City Energy, L.P. or its affiliates.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve on the board of directors or compensation committee of another public company that has an executive officer that serves on our Board or Compensation Committee. No member of our Board is an executive officer of another public company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

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

The following table sets forth certain information known to us, based on filings made under Section 13(d) and 13(g) of the Exchange Act, regarding the beneficial ownership of our common units as of March 5, 2026 by:

- each person, or group of affiliated persons, know to us to beneficially own more than 5% of our common units;
- each member of the board of directors of our General Partner;
- each name executive officer of our General Partner; and
- all of our directors and executive officers of our General Partner as a group.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Each of the holders listed has sole voting and investment power with respect to the common units beneficially owned by the holder unless noted otherwise, subject to community property laws where applicable. Unless otherwise noted, the address for each beneficial owner listed below is 14201 Wireless Way, Suite 300, Oklahoma City, OK 73134.

As of March 5, 2026, there were 168,218,770 common units outstanding.

	Common Units Beneficially Owned	
	Common Units[3]	Percentage of Common Units
Name of Beneficial Owner:		
Investment funds managed by Bayou City Energy Management LLC[(1)]	74,850,632	44.5 %
IKAV General Partner S.a r.l.	30,611,264	18.2 %
Kayne Anderson Capital Advisors L.P.	19,187,581	11.4 %
Tom L. Ward[(2)]	13,858,781	8.2 %
Kevin R. White	432,953	*
Michael E. Reel	79,713	*
William W. McMullen[(1)]	74,850,632	44.5 %
Edgar R. Giesinger	17,075	*
Stephen Perich	17,075	*
Christopher J. Burn	—	*
All executive officers and directors as a group (7 persons)	89,256,229	53.1 %

* Less than 1%.

(1) Represents the common units held by BCE-Mach Aggregator LLC (“BCE Aggregator”). Investment funds managed by Bayou City Energy Management LLC controls the investment decisions of BCE Aggregator and William W. McMullen has management control over these investment funds and accordingly may be deemed to share beneficial ownership of the common units held by BCE Aggregator. William W. McMullen disclaims beneficial ownership of such common units. The principal address for each of the above referenced entities is c/o Bayou City Energy, L.P., 2229 San Felipe Street, Suite 1075, Houston, TX 77019.

(2) Includes common units held through Mach Resources, over which Mr. Ward has control, common units held by the Tom L. Ward Family Foundation, over which Mr. Ward has control, and common units held in trust through the Tom L Ward 1992 Revocable Trust, of which 4,800,000 common units are pledged as collateral to secure certain personal indebtedness of Mr. Ward.

(3) Does not include unvested grants under the Long-Term Incentive Plan.

Equity Compensation Plan Information

The following table provides information with respect to our common units that may be issued under our existing equity compensation plans as of December 31, 2025.

Plan Category	Number of common units to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of common units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders			
Mach Natural Resources LP 2023 Long-Term Incentive Plan(1)	1,931,563	$—	7,242,822
Equity compensation plans not approved by unitholders			
None	—	$—	—
Total	1,931,563	$—	7,242,822

(1) All outstanding awards represent time-vesting and performance-vesting Award Units (including Time-Based Phantom Units and Performance Phantom Units) (each granted in tandem with a corresponding DER, which entitles

the recipient to receive a cash payment equal to the total distribution paid by the Company in respect of a common unit during the time the corresponding Award Unit is outstanding); there is no weighted average exercise price associated with these awards. If the vesting conditions are fulfilled, each Award Unit is settleable for one of our common units and is reflected as such above. Performance Phantom Unit awards with uncompleted performance conditions, which are also subject to a time-based vesting requirement, are reflected as the maximum amount of common units that would be earned based on the performance condition results. Because the number of common units to be issued upon settlement of outstanding Performance Phantom Units depends on the achievement of performance conditions, the number of common units actually issued may be substantially less than the number reflected in this column.

A description of the material terms of the Award Units (and corresponding DERs) granted under the Long-Term Incentive Plan to our Named Executive Officers as of December 31, 2025 is included within "Executive Compensation— Equity Incentives— 2023 Long-Term Incentive Plan" in Item 11 of Part III of this Annual Report, which description is incorporated into this Equity Compensation Plan Information disclosure by reference. The Long-Term Incentive Plan is incorporated by reference herein as Exhibit 10.1.

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

As of the date hereof, the Sponsor owns 74,850,632 common units representing an approximate 44.5% limited partner interest in us, and BCE-Mach Aggregator, which is controlled by the Sponsor, owns 80.3% of our General Partner. Tom L. Ward beneficially owns 13,858,781 common units (excluding any unvested grants under the Long-Term Incentive Plan) representing an approximate 8.2% limited partner interest in us and beneficially owns 19.7% of our General Partner through his ownership of Mach Resources. The Sponsor, who owns BCE-Mach Aggregator, and Tom L. Ward through his ownership of Mach Resources indirectly appoint all of the directors of our General Partner, which owns a non-economic general partner interest in us.

Policies and Procedures for Review of Related Party Transactions

A "Related Party Transaction" is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved will or may be expected to exceed $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. A "Related Person" means:

- a person who is or was (since the beginning of the Company's last completed fiscal year, even if they do not presently serve in that role) a director or director nominee of the Company;
- a person who is or was (since the beginning of the Company's last completed fiscal year, even if they do not presently serve in that role) a senior officer of the Company, which, among others, includes each vice president and officer of the Company that is subject to reporting under Section 16 of the Exchange Act;
- a greater than 5% beneficial owner of the Company's common units representing limited partner interests (a "5% Unitholder");
- a person who is an immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of a director, director nominee, senior officer or 5% Unitholder, and any person (other than a tenant or employee) sharing the household of the director, director nominee, senior officer or 5% Unitholder; or
- an entity that is owned or controlled by someone listed above, an entity in which someone listed above has a substantial ownership interest or control of the entity, or an entity which someone listed above is an executive officer or general partner, or holds a similar position.

Our Related Party Transactions Policy (the "RPT Policy") was adopted by our Board of Directors in October 2023. The RPT Policy required that, prior to entering into a Related Party Transaction, the Audit Committee shall review the material facts of the proposed transaction in advance. If advance Audit Committee review and approval of a Related Party Transaction is not feasible, then such Related Party Transaction will be reviewed and considered and, if the Audit Committee determines it to be appropriate and not inconsistent with the interests of the Company and its stockholders, ratified at the Audit Committee's next regularly scheduled meeting. In determining whether to approve or ratify such a Related Party Transaction, the Audit Committee will take into account, among other factors it deems appropriate, (1) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances, (2) the extent of the Related Person's interest in the transaction and (3) whether the Related Party Transaction is material to the Company.

Unless otherwise stated, each of the Related Party Transactions discussed below were authorized or consummated prior to our adoption of the RPT Policy. See Note 14 for additional information on Related Party Transactions.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our ongoing operations and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, were not the result of arm's length negotiations.

Operational Stage	
Distributions of available cash to affiliates of our general partner	We make cash distributions to our unitholders, including affiliates of our General Partner, pro rata.
	The affiliates of our General Partner (the Sponsor and Tom L. Ward through his ownership in Mach Resources) beneficially own 88,709,413 common units, representing approximately 52.7% of our outstanding common units and receive a pro rata percentage of the cash distributions that we distribute in respect thereof.
Payments to our general partner and its affiliates	The management, maintenance and operational functions of our business are currently provided by Mach Resources, an affiliate of our General Partner, pursuant to the MSA (as defined below). The MSA provides that we will reimburse Mach Resources for the direct and indirect costs associated with such services and pay an annual management fee of approximately $7.4 million. Neither our General Partner nor the Sponsor currently receive any management fee or other compensation with respect to the management of our business; however, to the extent they did provide services in the future, they would be entitled to reimbursement under the partnership agreement. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us.
Withdrawal or removal of our general partner	If our General Partner withdraws or is removed, its non-economic general partner interest will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our General Partner with respect to any common units or other units then held by our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Common Unit Purchase by BCE

On February 7, 2025, the Company completed a public offering of 12,903,226 common units at a price of $15.50 per common unit, resulting in proceeds to the Company of $193.2 million, after deducting underwriting fees (the "February 2025 Offering"). In connection with the February 2025 Offering, BCE-Mach Aggregator, an affiliate of our General Partner, purchased 5,161,290 common units in the February 2025 Offering at the public offering price, which accounted for $79.2 million of the proceeds received by the Company in the February 2025 Offering, after deducting underwriting fees. In connection therewith, the underwriters received a reduced underwriting discount on such common units purchased by BCE-Mach Aggregator compared to other common units sold to the public in the February 2025 Offering.

Agreements with Management

Tom L. Ward, our Chief Executive Officer, and certain affiliated entities of Mr. Ward have royalty and working interests in certain of our wells. The payments related to these certain interests were $272,752 for the year ended December 31, 2025.

Management Services Agreement

We have entered into a management services agreement ("MSA") with Mach Resources setting forth the operational services arrangements described below. Mach Resources is owned 50.5% by our Chief Executive Officer, Tom L. Ward, through the Tom L Ward 1992 Revocable Trust and 49.5% by WCT Resources LLC which is owned by certain trusts affiliated with Mr. Ward. Mach Resources provides certain management, maintenance and operational functions with respect to our assets as fully described in the MSA (the "Services"). We (i) pay Mach Resources an annual management fee of approximately $7.4 million and (ii) reimburse Mach Resources for the costs and expenses of the Services provided, including, but not limited to, (a) all reasonable third-party costs and expenses incurred by or paid by Mach Resources or its Affiliates in the performance of the Services, including the costs of any Person engaged by the Service Provider pursuant to the terms of the MSA, and (b) all general, administrative and supervision costs and expenses. We reimburse Mach Resources on a quarterly basis or at other intervals that we and Mach Resources may agree from time to time. Payments under the MSA to Mach Resources were $135.7 million for the year ended December 31, 2025. We anticipate that the size of the reimbursements to Mach Resources will vary with the size and scale of our operations, among other factors. The MSA has an initial term of two years and automatically extends for successive extension terms of one year each, unless terminated by either party in accordance with the MSA. In the MSA, both us and Mach Resources, an affiliate of our General Partner, and our respective affiliates agree to indemnify and hold harmless the other party from any and all losses arising out of or in connection with the agreement except for losses resulting from (i) fraud, gross negligence or willful misconduct of the other party, (ii) willful breach of the other party or (iii) employment claims made by Mach Resources employees.

Item 14. Principal Accountant Fees and Services

Our independent registered public accounting firm is Grant Thornton LLP, Oklahoma City, OK, Auditor Firm ID: 248.

Aggregate fees for professional services rendered for the Company by Grant Thornton LLP for the years ended December 31, 2025 and 2024, are presented in the following table.

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Audit fees	$ 1,594	$ 1,479
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$ 1,594	$ 1,479

The Audit Committee has determined that Grant Thornton LLP is independent for purposes of providing external audit services to the Company.

Audit Committee Policy for Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services

The Audit Committee has adopted procedures for pre-approving all audit and non-audit services provided by its independent accounting firm. These procedures include reviewing fee estimates for audit services and permitted recurring non-audit services, and authorizing the Company to execute letter agreements setting forth such fees. Audit Committee approval is required for any services to be performed by the independent accounting firm that are not specified in the letter agreements. The Audit Committee has delegated approval authority to the chairman of the Audit Committee, but any exercises of such authority are reported to the Audit Committee at the next meeting.

Procedures for Review, Approval or Ratification of Transactions with Related Persons

The Board has adopted policies for the review, approval and ratification of transactions with related persons. The Board has adopted a related party transactions policy, under which a director would be expected to bring to the attention of our General Counsel any conflict or potential conflict of interest that may arise between the director in his or her personal capacity or any affiliate of the director in his or her personal capacity, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the Board in light of the circumstances, be determined by our conflict committee or audit committee, as applicable.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the Board in accordance with the provisions of our partnership agreement. At the discretion of the Board in light of the circumstances, the resolution may be determined by the Board in its entirety, by the conflicts committee of the Board or by approval of our unitholders (other than the general partner and its affiliates).

Under our related party transactions policy, any executive officer will be required to avoid personal conflicts of interest unless approved by the Board.

The related party transactions policy described above was adopted in connection with the closing of the Offering, and as a result, the transactions described above were not reviewed according to such procedures.

Part IV

Item 15. Exhibit and Financial Statement Schedules

(a) Financial statements and financial statement schedules filed as part of this Annual Report are listed in the index included in Item 8 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.

(b) Exhibits. The following is a list of exhibits required to be filed as a part of this Annual Report in Item 15(b).

Exhibit Number	Description
2.1*†	Purchase and Sale Agreement, dated as of November 10, 2023, by and among Excalibur Resources, LLC, Travis Peak Resources, LLC, Paloma Partners IV, LLC and TPR Mid-Continent, LLC, as sellers, and Mach Natural Resources LP, as buyer (incorporated by reference to Exhibit 2.1 of the Partnership's Form 8-K filed on November 13, 2023).
2.2*†	Purchase and Sale Agreement, dated as of July 9, 2025 by and among Sabinal Energy Operating, LLC, Sabinal Resources, LLC and Sabinal CBP, LLC, as sellers, and Mach Natural Resources LP, as buyer (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 10, 2025).
2.3*†	Membership Interest Purchase Agreement, dated as of July 9, 2025 by and among VEPU Inc. and Simlog Inc., as sellers, and Mach Natural Resources LP, as buyer (incorporated by reference to Exhibit 2.2 to the Registrant's Current Report on Form 8-K filed with the SEC on July 10, 2025).
2.4*	First Amendment to Membership Interest Purchase Agreement, dated as of September 16, 2025, by and among Simlog Inc. and VEPU Inc., as sellers, and the Company, as buyer (incorporated by reference to Exhibit 2.3 of the Company's Form 8-K filed on September 17, 2025).
3.1*	Certificate of Limited Partnership of Mach Natural Resources LP (incorporated by reference to Exhibit 3.1 to the Partnership's Form S-1 filed on September 22, 2023).
3.2*	Amended and Restated Agreement of Limited Partnership of Mach Natural Resources LP (incorporated by reference to Exhibit 3.1 of the Partnership's Form 8-K filed on October 27, 2023).
3.3*	Amended and Restated Limited Liability Company Agreement of the General Partner (incorporated by reference to Exhibit 3.3 of the Partnership's Form 10-Q filed on December 7, 2023).
3.4*	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Form 8-K filed on June 13, 2024).
4.1**	Description of Capital Stock.
4.2*	Registration Rights Agreement, dated as of September 16, 2025, by and among Mach Natural Resources LP and each of the sellers party thereto (incorporated by reference to Exhibit 4.1 of the Company's Form 8-K filed on September 17, 2025).
10.1*††	Mach Natural Resources LP 2023 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 of the Partnership's Form 8-K filed on October 27, 2023).
10.2*††	Form of Mach Natural Resources LP 2023 Long-Term Incentive Plan Performance Unit Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Form 10-Q filed on June 30, 2024).
10.3*	Form of Mach Natural Resources LP 2023 Long-Term Incentive Plan Phantom Unit Agreement (Non-Employee Directors) (incorporated by reference to Exhibit 4.4 of the Partnership's Form S-8 filed on October 27, 2023).
10.4*	Form of Mach Natural Resources LP 2023 Long-Term Incentive Plan Phantom Unit Agreement (Executives) (incorporated by reference to Exhibit 4.5 of the Partnership's Form S-8 filed on October 27, 2023).
10.5*	Contribution Agreement, dated October 13, 2023, by and among Mach Natural Resources LP, Mach Natural Resources Holdco LLC, Mach Natural Resources Intermediate LLC and the other contributors party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on October 27, 2023).
10.6*	Management Services Agreement, dated October 27, 2023, by and between Mach Natural Resources LP and Mach Resources LLC (incorporated by reference to Exhibit 10.2 of the Partnership's Form 8-K filed on October 27, 2023).
10.7*	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to the Partnership's Registration Statement on Form S-1, filed on September 29, 2023).
10.8*	Term Loan Credit Agreement, dated December 28, 2023, among Mach Natural Resources LP, the guarantors party thereto, the lenders party thereto, Texas Capital Bank, as the administrative agent, and Chambers Energy Management, LP, as the loan commitment arranger (incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on December 29, 2023).

10.9*	Revolving Credit Agreement, dated December 28, 2023, among Mach Natural Resources LP, the guarantors party thereto, the lenders party thereto and MidFirst Bank, as the administrative agent (incorporated by reference to Exhibit 10.2 of the Partnership's Form 8-K filed on December 29, 2023).
10.10*††	Partnership's Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.2 of the Partnership's Form 8-K filed on May 9, 2024).
10.11*††	Form of Participation Agreement under the Partnership's Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.3 of the Partnership's Form 8-K filed on May 9, 2024).
10.12*††	First Amendment to Term Loan Credit Agreement, dated August 26, 2024, among the Partnership, the guarantors party thereto, the lenders party thereto, Texas Capital Bank, as the administrative agent, and Chambers Energy Management LP, as the loan commitment arranger (incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on August 30, 2024).
10.13*	First Amendment to Revolving Credit Agreement, dated August 26, 2024, among the Partnership, the guarantors party thereto, the lenders party thereto and MidFirst Bank, as the administrative agent (incorporated by reference to Exhibit 10.2 of the Partnership's Form 8-K filed on August 30, 2024).
10.14*†	Revolving Credit Agreement, dated February 27, 2025, among Mach Natural Resources LP, the lenders and issuing banks party thereto from time to time and Truist Bank, as the administrative agent and collateral agent incorporated by reference to Exhibit 10.1 of the Partnership's Form 8-K filed on February 27, 2026).
10.15*	Letter Agreement, dated as of July 8, 2025, by and among Mach Natural Resources LP, the lenders party thereto and Truist Bank, as administrative agent and collateral agent (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 10, 2025).
10.16*	First Amendment to Credit Agreement, dated as of September 12, 2025, by and among Mach Natural Resources LP, the subsidiaries of Mach Natural Resources LP party thereto, the lenders and issuing banks party thereto and Truist Bank, as the administrative agent and collateral agent (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 17, 2025).
19.1**	Mach Natural Resources LP Insider Trading Policy.
21.1**	List of Subsidiaries of Mach Natural Resources LP.
23.1**	Consent of Grant Thornton LLP.
23.2**	Consent of Cawley, Gillespie & Associates.
23.3**	Consent of Netherland, Sewell & Associates, 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 Mach Natural Resources LP (incorporated by reference to Exhibit 97.1 of the Partnership's Form 10-K filed on March 13, 2025).
99.1**	Report of Cawley, Gillespie & Associates, dated January 15, 2026, of reserves of Mach Natural Resources LP, as of December 31, 2025.
99.2*	Report of Cawley, Gillespie & Associates, dated January 21, 2025, of reserves of Mach Natural Resources LP, as of December 31, 2024 (incorporated by reference to Exhibit 99.4 of the Partnership's Form 8-K filed on February 5, 2025).
99.3**	Report of Netherland, Sewell & Associates, dated January 16, 2026, of reserves of Mach Natural Resources LP, as of December 31, 2025.
99.4**	Report of Netherland, Sewell & Associates, dated January 15, 2026, of reserves of Mach Natural Resources LP, as of December 31, 2025.
101.INS**	Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because XBRL tags are embedded within the Inline XBRL document
101.SCH**	Inline XBRL Taxonomy Extension Schema Document
101.CAL**	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	Inline XBRL Taxonomy Extension Label Linkbase Document

101.PRE**	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104**	Cover Page Interactive Data File (embedded within the Inline XBRL document)

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* Incorporated herein by reference as indicated.

** Filed herewith.

*** Furnished herewith.

† 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, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Mach Natural Resources LP
(Registrant)

By: **Mach Natural Resources GP LLC, its general partner**

Date: March 12, 2026

By: /s/ Tom L. Ward
Name: Tom L. Ward
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 12, 2026.

Name	Title
/s/ Tom L. Ward Tom L. Ward	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Kevin R. White Kevin R. White	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
/s/ William W. McMullen William W. McMullen	Chairman of the Board
/s/ Edgar R. Giesinger Edgar R. Giesinger	Director
/s/ Stephen Perich Stephen Perich	Director
/s/ Christopher J. Burn Christopher J. Burn	Director

Exhibit 4.1

DESCRIPTION OF SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

DESCRIPTION OF THE COMMON UNITS

The following description of our common units is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our Certificate of Limited Partnership, dated as of May 26, 2023, Amended and Restated Agreement of Limited Partnership, dated as of October 27, 2023 (as amended, the "partnership agreement"), both of which are filed as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.1 is a part. We encourage you to read our partnership agreement and the applicable provisions of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") for additional information.

The Units

The common units represent limited partner interests ("common units") in Mach Natural Resources, LP. The holders of common units are entitled to participate in partnership distributions and exercise the rights and privileges available to limited partners under our partnership agreement.

Our common units are listed on the New York Stock Exchange under the symbol "MNR."

Transfer Agent and Registrar

Duties

Equiniti Trust Company, LLC, a New York limited liability trust company, serves as the registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates or to cover taxes and other governmental charges;
- special charges for services requested by common unitholders; and
- other similar fees or charges.

There is no charge to our unitholders for disbursements of our cash distributions. We indemnify the transfer agent, its agents and each of their unitholders, directors, officers and employees against all claims and losses that may arise out of their actions for their activities in that capacity, except for any liability due to any gross negligence or willful misconduct of the indemnitee.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed, Mach Natural Resources GP LLC (our "general partner") may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of our partnership agreement; and
- gives the consents, waivers and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status and/or the nationality, citizenship or other related status of our limited partners (and their owners, to the extent relevant) and to permit our general partner to redeem the units held by any person (i) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (ii) who fails to comply with the procedures established to obtain such proof.

The redemption price in the case of such a redemption will be the average of the daily closing prices per common unit for the 20 consecutive trading days immediately prior to the date set for redemption. Please read "The Partnership Agreement—Non-Citizen Unitholders; Redemption."

In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units. Our general partner will cause any transfers to be recorded on our books and records from time to time (or shall cause the transfer agent to do so, as applicable).

The transferor of common units will have a duty to provide the transferee with all information that may be necessary to transfer the common units. The transferor will not have a duty to ensure the execution of the transfer application and certification by the transferee and will have no liability or responsibility if the transferee neglects or chooses not to execute and forward the transfer application and certification to the transfer agent.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing transfers of securities.

OUR CASH DISTRIBUTION POLICY

General

Our partnership agreement requires us to distribute all of our available cash each quarter. Our cash distribution policy reflects a basic judgment that our unitholders generally will be better served by us distributing our available cash, after costs, expenses and reserves, rather than retaining it. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions from our available cash in the aforementioned or any other amount, and our general partner has considerable discretion to determine the amount of cash available for distribution each quarter.

Because our policy is to distribute all available cash we generate each quarter, without reserving cash for future distributions or borrowing to pay distributions during periods of low revenue, our unitholders will have direct exposure to fluctuations in the amount of cash generated by our business. Our quarterly cash distributions from our available cash, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in the performance of our operators and revenue caused by fluctuations in the prices of oil and natural gas. Such variations may be significant.

Definition of Available Cash

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner to:

    - provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;
    - comply with applicable law, any of our debt instruments or other agreements; or
    - provide funds for distributions to our unitholders for any one or more of the next four quarters;
- *plus*, all cash and cash equivalents on hand on the date of determination resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter;
- *plus,* if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination resulting from working capital borrowings made after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Methods of Distribution

We distribute available cash to our unitholders, pro rata. Our partnership agreement permits, but does not require, us to borrow funds to make distributions to our unitholders. Accordingly, there is no guarantee that we will pay any distribution on the units in any quarter.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future acquire common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Distributions of Cash Upon Liquidation

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment (or establishing a reserve for payment) of our creditors. We will distribute any remaining proceeds to our unitholders, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of the partnership agreement.

Organization and Duration

Our partnership was organized under Delaware law and will have a perpetual existence unless dissolved, wound up and terminated pursuant to the terms of our partnership agreement and the Delaware Act.

Purpose

Our purpose under our partnership agreement is to engage in any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law. However, our general partner may not cause us to engage, directly or indirectly, in any business activity that it determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, except as otherwise provided below under "—Election to be Treated as a Corporation."

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the ownership, acquisition, exploitation and development of oil and natural gas properties and the ownership, acquisition and operation of related assets, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described under "—Limited Liability."

Limited Voting Rights

The following is a summary of the unitholder vote required for each of the matters specified below. Matters that call for the approval of a "unit majority" require the approval of a majority of the outstanding common units.

Affiliates of our general partner (Bayou City Energy Management LLC and its affiliates (collectively, the "Sponsor") and Tom L. Ward) have the ability to control the passage of, as well as the ability to control the defeat of, any amendment which requires a unit majority by virtue of their ownership.

In voting their common units, our general partner and its affiliates (the Sponsor and Tom L. Ward) have no duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. The holders of a majority of the common units (including common units deemed owned by our general partner and its affiliates) entitled to vote at the meeting, represented in person or by proxy shall constitute a quorum at a meeting of common unitholders, unless any such action requires approval by holders of a greater percentage of such units in which case the quorum shall be such greater percentage.

Issuance of additional units	No approval right. Please read "—Issuance of Additional Partnership Interests."
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of our unitholders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority, in certain circumstances. Please read "—Merger, Consolidation, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read "—Termination and Dissolution."
Continuation of our business upon certain events of dissolution	Unit majority. Please read "—Termination and Dissolution."

Withdrawal of our general partner	Under most circumstances, the approval of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates (the Sponsor and Tom L. Ward), is required for the withdrawal of our general partner in a manner that would cause a dissolution of our partnership. Please read "—Withdrawal or Removal of Our General Partner."
Removal of our general partner	Requires the vote of not less than $66^{2}/_{3}$% of the outstanding common units, including units held by our general partner and its affiliates (the Sponsor and Tom L. Ward), voting as a single class. Please read "—Withdrawal or Removal of Our General Partner."
Transfer of our general partner interest	Our general partner may transfer any or all of its general partner interest in us without a vote of our unitholders. Please read "—Transfer of General Partner Interest."
Transfer of ownership interests in our general partner	No unitholder approval required. Please read "—Transfer of Ownership Interests in Our General Partner."
Election to be treated as a corporation	No approval right. Please read "—Election to be Treated as a Corporation."

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. The foregoing provision will not apply to any claims as to which the Court of Chancery determines that there is an indispensable party not subject to the jurisdiction of such court, which is rested in the exclusive jurisdiction of a court or forum other than such court (including claims arising under the Exchange Act), or for which such court does not have subject matter jurisdiction, or to any claims arising under the Securities Act and, unless we consent in writing to the selection of an alternative forum, the United States federal district courts will be the sole and exclusive forum for resolving any action asserting a claim arising under the Securities Act. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules or regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain such Securities Act claims. To prevent having to litigate claims in multiple jurisdictions and the threat of inconsistent or contrary rulings by different courts, among other considerations, the partnership agreement provides that, unless we consent in writing to the selection of an alternative forum, United States federal district courts shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act. There is uncertainty as to whether a court would enforce the forum provision with respect to claims under the federal securities laws. If a court were to find these provisions of our amended and restated agreement of limited partnership 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 business, financial condition or results of operations.

Our partnership agreement also provides that each limited partner waives the right to trial by jury in any such claim, suit, action or proceeding, including any claim under the U.S. federal securities laws, to the fullest extent permitted by applicable law. If a lawsuit is brought against us under our partnership agreement, it may be heard only by a judge or justice of the applicable trial court, which would be conducted according to different civil procedures and may result in different outcomes than a trial by jury would have, including results that could be less favorable to the plaintiffs in any such action. No unitholder can waive compliance with respect to the U.S. federal securities laws and the rules and regulations promulgated thereunder. If the partnership or one of the partnership unitholders opposed a jury trial demand based on the waiver, the applicable court would determine whether the waiver was enforceable based on the facts and circumstances of that case in accordance with applicable state and federal laws. To our knowledge, the enforceability of a contractual pre-dispute jury trial waiver in connection with claims arising under the U.S. federal securities laws has not been finally adjudicated by the United States Supreme Court. However, we believe that a contractual pre-dispute jury trial waiver provision is generally enforceable, including under the laws of the State of Delaware, which govern our partnership agreement.

By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other courts in Delaware) in connection with any such claims, suits, actions or proceedings.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he or she otherwise acts in conformity with the provisions of our partnership agreement, his or her liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he or she is obligated to contribute to us for his or her common units plus his or her share of any undistributed profits and assets. If it were determined, however, that the right or exercise of the right by our limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to the partnership agreement; or
- to take other action under the partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then our limited partners could be held personally liable for our obligations under Delaware law, to the same extent as our general partner. This liability would extend to persons who transact business with us and reasonably believe that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our operating subsidiaries conduct business in Oklahoma, Kansas and Texas, and we may have operating subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as an owner of our operating subsidiary may require compliance with legal requirements in the jurisdictions in which our operating subsidiary conducts business, including qualifying our operating subsidiary to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership in our subsidiaries or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by our limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted “participation in the control” of our business for purposes of the statutes of any relevant jurisdiction, then our limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of our limited partners.

Issuance of Additional Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have special voting or other rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity interests, which may effectively rank senior to our common units.

Our general partner has the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units or other partnership interests whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the aggregate percentage interest in us of our general partner and its affiliates, including such interest represented by common units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner.

However, our general partner has no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. To adopt a proposed amendment, other than the amendments discussed below under “—Opinion of Counsel and Unitholder Approval,” our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of our limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole and absolute discretion.

The provisions of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates (the Sponsor and Tom L. Ward)).

No Limited Partner Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate for us to qualify or to continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we, nor our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for U.S. federal income tax purposes except as otherwise provided below under "—Election to be Treated as a Corporation.";
- a change in our fiscal year or taxable year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from being subjected, in any manner to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940, or the Employee Retirement Income Security Act of 1974 or Section 4975 of the U.S. Internal Revenue Code of 1986, as amended;
- an amendment that sets forth the designations, preferences, rights, powers and duties of any class or series of additional partnership securities or rights to acquire partnership securities, that our general partner determines to be necessary or appropriate or advisable for the authorization or issuance of additional partnership securities or rights to acquire partnership securities;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement or plan of conversion that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate to reflect and account for the formation by us of, or our investment in, any corporation, partnership, limited liability company, joint venture or other entity, as otherwise permitted by our partnership agreement;
- any amendment necessary to require our limited partners to provide a statement, certification or other evidence to us regarding whether such limited partner is subject to U.S. federal income taxation on the income generated by us and to provide for the ability of our general partner to redeem the units of any limited partner who fails to provide such statement, certification or other evidence;
- an amendment that our general partner determines to be necessary or appropriate or advisable in connection with conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect our limited partners (or any particular class of limited partners) in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of our units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which our units are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in the prospectus used in our initial public offering or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will not affect the limited liability of any limited partner under Delaware law. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding common units unless we first obtain such an opinion.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the holders of the type or class of units so affected, but no vote will be required by the holders of any class or classes or type or types of units that our general partner determines are not adversely affected in any material respect. Any amendment that reduces the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased.

Merger, Consolidation, Sale or Other Disposition of Assets

A merger, consolidation, or conversion of us requires the prior consent of our general partner. However, our general partner has no duty or obligation to consent to any merger, consolidation, or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interest of us or our limited partners other than the implied contractual covenant of good faith and fair dealing.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us, among other things, to sell, exchange or otherwise dispose of all or substantially all of our and our subsidiaries' assets in a single transaction or a series of related transactions, including by way of merger, consolidation, conversion or other combination or sale of ownership interests of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger, consolidation or conversion without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction will not result in an amendment to our partnership agreement (other than an amendment that the general partner could adopt without the consent of the other partners), each of our units will be an identical unit of our partnership following the transaction, and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide our limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger, consolidation or conversion, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement. We will dissolve upon:

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner, other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or a withdrawal or removal followed by approval and admission of a successor;
- the election of our general partner to dissolve us, if approved by the holders of a unit majority;
- the entry of a decree of judicial dissolution of our partnership pursuant to the provisions of the Delaware Act; or
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law.

Upon a dissolution under the first bullet above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and
- neither our partnership nor our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Our Cash Distribution Policy." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to December 31, 2033, without obtaining the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates (the Sponsor and Tom L. Ward), and furnishing an opinion of counsel regarding limited liability and tax matters. On or after December 31, 2033, our general partner may withdraw as our general partner without first obtaining approval of any unitholder by giving at least 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement.

Notwithstanding the information above, our general partner may withdraw as our general partner without unitholder approval upon 90 days' notice to our limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates (the Sponsor and Tom L. Ward). In addition, our partnership agreement permits our general partner to sell or otherwise transfer all of its general partner interest in us without the approval of our unitholders. Please read "—Transfer of General Partner Interest."

Upon voluntary withdrawal of our general partner by giving notice to the other partners, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree to continue our business by appointing a successor general partner. Please read "—Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 $^{2}/_{3}$% of our outstanding units, voting together as a single class, including units held by our general partner and its affiliates (the Sponsor and Tom L. Ward), and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of our outstanding common units. The ownership of more than 33$^{1}/_{3}$% of our outstanding units by our general partner and its affiliates (the Sponsor and Tom L. Ward) would give them the practical ability to prevent our general partner's removal.

In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner's general partner interest for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and its affiliate and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and its affiliate and the successor general partner will determine the fair market value. If the departing general partner and its affiliate and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Our general partner may transfer all or any of its general partner interest to an affiliate or a third party without the approval of our unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates (the Sponsor and Tom L. Ward) may at any time transfer common units to one or more persons without unitholder approval.

Transfer of Ownership Interests in Our General Partner

At any time, the members of our general partner may sell or transfer all or part of their membership interests in our general partner to an affiliate or a third party without the approval of our unitholders.

Election to be Treated as a Corporation

If at any time our general partner determines that (i) we should no longer be characterized as a partnership but instead as an entity taxed as a corporation for U.S. federal income tax purposes or (ii) common units held by some or all unitholders should be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us (a “parent corporation”), then our general partner may, without unitholder approval, reorganize us and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause us to engage in a merger or other transaction pursuant to which common units held by some or all unitholders will be converted into or exchanged for interests in the parent corporation. In addition, if our general partner causes partnership interests in us to be held by a parent corporation, our existing owners may choose to retain their partnership interests in us rather than convert or exchange their partnership interests into parent corporation shares. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may vary depending on the unitholder’s particular situation and may vary from the tax liability of each of our existing owners. Our general partner has no duty or obligation to make any such determination or take any such actions, however, and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in a manner not adverse to the best interests of us or our limited partners.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates (the Sponsor and Tom L. Ward) acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner.

Limited Call Right

If at any time our general partner and its affiliates (the Sponsor and Tom L. Ward) own more than 95% of our then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days’ notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed.

As a result of our general partner’s right to purchase outstanding limited partner interests, a holder of limited partner interests may have its limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The U.S. federal income tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of its common units in the market.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of common units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by our unitholders may be taken either at a meeting of our unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take such action at a meeting. Meetings of our unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, entitled to vote at the meeting represented in person or by proxy, will constitute a quorum unless any action by our unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Partnership Interests." However, if at any time any person or group, other than our general partner and its affiliates (the Sponsor and Tom L. Ward) or a direct or subsequently approved transferee of our general partner or its affiliates or a transferee of that person or group approved by our general partner or a person or group specifically approved by our general partner, or the the board of directors of our general partner, as applicable, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held by a nominee or in a street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent or an exchange agent.

Status as Limited Partner

By transfer of any common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described above under "— Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Unitholders; Redemption

We may acquire interests in oil and natural gas leases on United States federal lands in the future. To comply with certain U.S. laws relating to the ownership of interests in oil and natural gas leases on federal lands, our general partner, acting on our behalf, may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status and/or the nationality, citizenship or other related status of our limited partners (and their owners, to the extent relevant) and to permit our general partner to redeem the units held by any person (i) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (ii) who fails to comply with the procedures established to obtain such proof. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption. Further, the units held by such unitholder will not be entitled to any voting rights and may not receive distributions in-kind upon our liquidation.

Furthermore, we have the right to redeem all of the common units of any holder that our general partner concludes is an Ineligible Holder (as defined in our partnership agreement) or fails to furnish the information requested by our general partner. The redemption price in the event of such redemption for each unit held by such unitholder will be the current market price of such unit (the date of determination of which shall be the date fixed for redemption). The redemption price will be paid, as determined by our general partner, in cash or by delivery of a promissory note. Any such promissory note will bear interest at the rate of 5% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof.

Indemnification

Under our partnership agreement, unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such person acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a director, officer, manager, managing member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as a director, officer, manager, managing member, partner, fiduciary or trustee of another person at the request of our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance covering liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation, and other amounts paid to persons who perform services for us or on our behalf, and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us. The expenses for which we are required to reimburse our general partner are not subject to any caps or other limits.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For financial reporting and tax purposes, our fiscal year is the calendar year.

We mail or make available to record holders of common units, within 105 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent registered public accounting firm. Except for our fourth quarter, we also mail or make available a report containing unaudited financial statements within 50 days after the close of each quarter. We are deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website which we maintain.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on the cooperation of our unitholders in supplying us with specific information. Every unitholder will receive information to assist it in determining its federal and state tax liability and filing its federal and state income tax returns, regardless of whether such unitholder supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, obtain:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement and our certificate of limited partnership and related amendments thereto; and
- certain information regarding the status of our business and financial condition.

Our general partner may, and intends to, keep confidential from the limited partners, trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the right to information that a limited partner would otherwise have under Delaware law.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner.

INSIDER TRADING POLICY

PURPOSE

This Insider Trading Policy (the "Policy") provides guidelines with respect to transactions in the securities of Mach Natural Resources LP (the "Partnership") and the handling of confidential information about the Partnership and the companies with which the Partnership does business. The board of directors (the "Board") of Mach Natural Resources GP LLC (the "General Partner"), the general partner of the Partnership, has adopted this Policy to promote compliance with federal, state and foreign securities laws that prohibit certain persons who are aware of material nonpublic information about a company from: (i) trading in securities of that company; or (ii) providing material nonpublic information to other persons who may trade on the basis of that information. Regulators have adopted sophisticated surveillance techniques to identify insider trading transactions, and it is important to the General Partner to avoid even the appearance of impropriety.

PERSONS SUBJECT TO THE POLICY

This Policy applies to all directors, officers and employees of the General Partner and its subsidiaries, including the Partnership. The General Partner may also determine that other persons should be subject to this Policy, such as contractors or consultants who have access to material nonpublic information. This Policy also applies to family members, other members of a person's household and entities controlled by a person covered by this Policy, as described below.

TRANSACTIONS SUBJECT TO THE POLICY

This Policy applies to transactions in the Partnership's securities (collectively referred to in this Policy as "Partnership Securities"), including the Partnership's common units, options to purchase common units, or any other type of securities that the Partnership may issue, including (but not limited to) common unit appreciation rights, restricted units, phantom units, as well as derivative securities that are not issued by the Partnership, such as exchange-traded put or call options or swaps relating to Partnership Securities. Transactions subject to this Policy include purchases, sales and *bona fide* gifts of Partnership Securities.

INDIVIDUAL RESPONSIBILITY

Persons subject to this Policy have ethical and legal obligations to maintain the confidentiality of information about the Partnership and to not engage in transactions in Partnership Securities while in possession of material nonpublic information. Each individual is responsible for making sure that he or she complies with this Policy, and that any family member, household member or entity whose transactions are subject to this Policy, as discussed below, also comply with this Policy. In all cases, the responsibility for determining whether an individual is in possession of material nonpublic information rests with that individual, and any action on the part of the General Partner, the General Counsel or any other employee or director pursuant to this Policy (or otherwise) does not in any way constitute legal advice or insulate an individual from liability under applicable securities laws. You could be subject to severe legal penalties and disciplinary action by the General Partner for any conduct prohibited by this

Policy or applicable securities laws, as described below in more detail under the heading “Consequences of Violations.”

STATEMENT OF POLICY

It is the policy of the General Partner that no director, officer or other employee of the General Partner (or any other person designated by this Policy or by the General Counsel as subject to this Policy) who is aware of material nonpublic information relating to the Partnership may, directly, or indirectly through family members or other persons or entities:

1. Engage in transactions in Partnership Securities, except as otherwise specified in this Policy under the headings “Transactions Under Partnership Plans and Certain Other Transactions” and “Rule 10b5-1 Plans”;

2. Recommend the purchase or sale of any Partnership Securities;

3. Disclose material nonpublic information to persons within the General Partner whose jobs do not require them to have that information, or outside of the General Partner to other persons, including, but not limited to, family, friends, business associates, investors and expert consulting firms, unless any such disclosure is made in accordance with the General Partner’s policies regarding the protection or authorized external disclosure of information regarding the Partnership; or

4. Assist anyone engaged in the above activities.

In addition, it is the policy of the General Partner that no director, officer or other employee of the General Partner (or any other person designated as subject to this Policy) who, in the course of working for the General Partner, learns of material nonpublic information about a company with which the Partnership does business, including a customer or supplier of the Partnership, or that is involved in a potential transaction or business relationship with the Partnership, may trade in that company’s securities until the information becomes public or is no longer material.

There are no exceptions to this Policy, except as specifically noted herein. Transactions that may be necessary or justifiable for independent reasons (such as the need to raise money for an emergency expenditure), or small transactions, are not excepted from this Policy. The securities laws do not recognize any mitigating circumstances, and, in any event, even the appearance of an improper transaction must be avoided to preserve the General Partner’s reputation for adhering to the highest standards of conduct.

DEFINITION OF MATERIAL NONPUBLIC INFORMATION

<u>Material Information</u>: Information is considered “material” if a reasonable investor would consider that information important in making a decision to buy, hold or sell securities. Any information that could be expected to affect a company’s security price, whether it is positive or negative, should be considered material. There is no bright-line standard for assessing materiality; rather, materiality is based on an assessment of all of the facts and circumstances, and is often evaluated by enforcement authorities with the benefit of hindsight. While it is not possible to define all categories of material information, some examples of information that ordinarily would be regarded as material are:

- Projections of future earnings or losses, or other earnings guidance;
- Changes to previously announced earnings guidance, or the decision to suspend earnings guidance;
- A pending or proposed merger, acquisition or tender offer;
- A pending or proposed acquisition or disposition of a significant asset;
- A pending or proposed joint venture;
- A Partnership restructuring;
- Significant related party transactions;
- A change in distribution policy, the declaration of a unit split, or an offering of additional securities;
- Bank borrowings or other financing transactions out of the ordinary course;
- The establishment of a repurchase program for Partnership Securities;
- A change in the Partnership’s pricing or cost structure;
- Major marketing changes;
- A change in management;
- A change in auditors or notification that the auditor’s reports may no longer be relied upon;
- Development of a significant new product, process, or service;
- Pending or threatened significant litigation, or the resolution of such litigation;
- Impending bankruptcy or the existence of severe liquidity problems;
- The gain or loss of a significant customer or supplier;

- Significant cybersecurity incidents; and
- The imposition of a ban on trading in Partnership Securities or the securities of another company.

If you are unsure whether information is material, you should either consult the General Counsel before making any decision to disclose such information (other than to persons who need to know it) or to trade in or recommend trading in securities to which that information relates or assume that the information is material.

<u>When Information is Considered Public</u>: Information that has not been disclosed to the public is generally considered to be nonpublic information. In order to establish that the information has been disclosed to the public, it may be necessary to demonstrate that the information has been widely disseminated. Information generally would be considered widely disseminated if it has been disclosed through the Dow Jones “broad tape,” newswire services, a broadcast on widely- available radio or television programs, publication in a widely-available newspaper, magazine or news website, or public disclosure documents filed with the SEC that are available on the SEC’s website. By contrast, information would likely not be considered widely disseminated if it is available only to the General Partner’s employees, or if it is only available to a select group of analysts, brokers and institutional investors.

Once information is widely disseminated, it is still necessary to afford the investing public with sufficient time to absorb the information. As a general rule, information should not be considered fully absorbed by the marketplace until after the first business day after the day on which the information is released. If, for example, the Partnership were to make an announcement on a Monday, you should not trade in Partnership Securities until Wednesday. Depending on the particular circumstances, the General Partner may determine that a longer or shorter period should apply to the release of specific material nonpublic information.

TRANSACTIONS BY FAMILY MEMBERS AND OTHERS

This Policy applies to your family members who reside with you (including a spouse, a child, a child away at college, stepchildren, grandchildren, parents, stepparents, grandparents, siblings and in-laws), anyone else who lives in your household, and any family members who do not live in your household but whose transactions in Partnership Securities are directed by you or are subject to your influence or control, such as parents or children who consult with you before they trade in Partnership Securities (collectively referred to as “Family Members”). You are responsible for the transactions of these other persons and therefore should make them aware of the need to confer with you before they trade in Partnership Securities, and you should treat all such transactions for the purposes of this Policy and applicable securities laws as if the transactions were for your own account. This Policy does not, however, apply to personal securities transactions of Family Members where the purchase or sale decision is made by a third party not controlled by, influenced by or related to you or your Family Members.

TRANSACTIONS BY ENTITIES THAT YOU INFLUENCE OR CONTROL

This Policy applies to any entities that you influence or control, including any corporations, partnerships or trusts (collectively referred to as "Controlled Entities"), and transactions by these Controlled Entities should be treated for the purposes of this Policy and applicable securities laws as if they were for your own account.

TRANSACTIONS UNDER PARTNERSHIP PLANS AND CERTAIN OTHER TRANSACTIONS

This Policy does not apply in the case of the following transactions, except as specifically noted:

1. Unit Option Exercises: This Policy does not apply to the exercise of an employee unit option acquired pursuant to the Partnership's plans, or to the exercise of a tax withholding right pursuant to which a person has elected to have the Partnership withhold units subject to an option to satisfy tax withholding requirements. This Policy does apply, however, to any sale of units as part of a broker-assisted cashless exercise of an option, or any other market sale for the purpose of generating the cash needed to pay the exercise price of, or the tax liability associated with, an option.

2. Restricted Unit Awards: This Policy does not apply to the vesting of restricted units, or the exercise of a tax withholding right pursuant to which you elect to have the Partnership withhold units to satisfy tax withholding requirements upon the vesting of any restricted units. The Policy does apply, however, to any market sale of the Partnership Securities received upon such vesting.

3. 401(k) Plan: This Policy does not apply to purchases of Partnership Securities in the Partnership's 401(k) plan resulting from your periodic contribution of money to the plan pursuant to your payroll deduction election. This Policy does apply, however, to certain elections you may make under the 401(k) plan, including: (a) an election to increase or decrease the percentage of your periodic contributions that will be allocated to the Partnership unit fund; (b) an election to make an intra-plan transfer of an existing account balance into or out of the Partnership unit fund; (c) an election to borrow money against your 401(k) plan account if the loan will result in a liquidation of some or all of your Partnership unit fund balance; and (d) an election to pre-pay a plan loan if the pre-payment will result in allocation of loan proceeds to the Partnership unit fund.

4. Employee Unit Purchase Plan: This Policy does not apply to purchases of Partnership Securities in the employee unit purchase plan resulting from your periodic or lump sum contribution of money to the plan pursuant to the election you made at the time of your enrollment in the plan. This Policy does apply, however, to your initial election to participate in the plan, changes to your election to participate in the plan for any enrollment period, and to your sales of Partnership Securities purchased pursuant to the plan.

5. Distribution Reinvestment Plan: This Policy does not apply to purchases of Partnership Securities under the Partnership's distribution reinvestment plan resulting from your reinvestment of distributions paid on Partnership Securities. This Policy does apply, however, to voluntary purchases of Partnership Securities resulting from additional contributions you choose to make to the distribution reinvestment plan, and to your election to participate in the plan or increase your level of

participation in the plan. This Policy also applies to your sale of any Partnership Securities purchased pursuant to the plan.

6. Other Similar Transactions: Any other purchase of Partnership Securities from the Partnership or sales of Partnership Securities to the Partnership are not subject to this Policy.
7. Mutual Funds: Transactions in mutual funds that are invested in Partnership Securities are not transactions subject to this Policy.
8. Bona Fide Gifts: Bona fide gifts of Partnership Securities are not transactions subject to this Policy, unless the person making the gift knows or is reckless in not knowing that the recipient intends to sell the Partnership Securities while the person making the gift is aware of material nonpublic information, or the person making the gift is subject to the trading restrictions specified below under the heading "Pre-Clearance and Blackouts" and the sales by the recipient of the Partnership Securities occur during a blackout period.

SPECIAL AND PROHIBITED TRANSACTIONS

The General Partner has determined that there is a heightened legal risk and/or the appearance of improper or inappropriate conduct if the persons subject to this Policy engage in certain types of transactions. It therefore is the General Partner's policy that any persons covered by this Policy may not engage in any of the following transactions, or should otherwise consider the General Partner's preferences as described below:

Short-Term Trading: Short-term trading of Partnership Securities may be distracting to the person and may unduly focus the person on the Partnership's short-term stock market performance instead of the Partnership's long-term business objectives. For these reasons, any director, officer or other employee of the General Partner who purchases Partnership Securities in the open market may not sell any Partnership Securities of the same class during the six months following the purchase (or vice versa).

Short Sales: Short sales of Partnership Securities (*i.e.*, the sale of a security that the seller does not own) may evidence an expectation on the part of the seller that the securities will decline in value, and therefore have the potential to signal to the market that the seller lacks confidence in the Partnership's prospects. In addition, short sales may reduce a seller's incentive to seek to improve the Partnership's performance. For these reasons, short sales of Partnership Securities are prohibited. In addition, Section 16(c) of the Exchange Act prohibits officers and directors from engaging in short sales. (Short sales arising from certain types of hedging transactions are governed by the paragraph below captioned "Hedging Transactions.")

Publicly-Traded Options: Given the relatively short term of publicly-traded options, transactions in options may create the appearance that a director, officer or employee is trading based on material nonpublic information and focus a director's, officer's or other employee's attention on short-term performance at the expense of the Partnership's long-term objectives. Accordingly, transactions in put options, call options or other derivative securities, on an exchange or in any other organized market, are prohibited by this Policy. (Option positions arising from certain types of hedging transactions are governed by the next paragraph below.)

Hedging Transactions: Hedging or monetization transactions can be accomplished through a number of possible mechanisms, including through the use of financial instruments such as prepaid variable forwards, equity swaps, collars and exchange funds. Such hedging transactions may permit a director, officer or employee to continue to own Partnership Securities obtained through employee benefit plans or otherwise, but without the full risks and rewards of ownership. When that occurs, the director, officer or employee may no longer have the same objectives as the Partnership's other unitholders. Therefore, the General Partner prohibits you from engaging in such transactions. Any person wishing to enter into such an arrangement must first submit the proposed transaction for approval by the General Counsel. Any request for pre-clearance of a hedging or similar arrangement must be submitted to the General Counsel at least two weeks prior to the proposed execution of documents evidencing the proposed transaction and must set forth a justification for the proposed transaction.

Margin Accounts and Pledged Securities: Securities held in a margin account as collateral for a margin loan may be sold by the broker without the customer's consent if the customer fails to meet a margin call. Similarly, securities pledged (or hypothecated) as collateral for a loan may be sold in foreclosure if the borrower defaults on the loan. Because a margin sale or foreclosure sale may occur at a time when the pledger is aware of material nonpublic information or otherwise is not permitted to trade in Partnership Securities, directors, officers and other employees are prohibited from holding Partnership Securities in a margin account or otherwise pledging Partnership Securities as collateral for a loan; provided, that the Board or General Counsel may except from this prohibition a margin loan or pledge of securities where the director or officer is clearly able to demonstrate the financial ability to repay the loan without resort to the pledged securities, and notice is given to the Audit Committee. (Pledges of Partnership Securities arising from certain types of hedging transactions are governed by the paragraph above captioned "Hedging Transactions.")

Standing and Limit Orders: Standing and limit orders (except standing and limit orders under approved Rule 10b5-1 Plans, as described below) create heightened risks for insider trading violations similar to the use of margin accounts. There is no control over the timing of purchases or sales that result from standing instructions to a broker, and as a result the broker could execute a transaction when a director, officer or other employee is in possession of material nonpublic information. The General Partner therefore discourages placing standing or limit orders on Partnership Securities. If a person subject to this Policy determines that they must use a standing order or limit order, the order should be limited to short duration and should otherwise comply with the restrictions and procedures outlined below under the heading "Pre-Clearance and Blackouts."

PRE-CLEARANCE AND BLACKOUTS

The General Partner has established additional procedures in order to assist the General Partner in the administration of this Policy, to facilitate compliance with laws prohibiting insider trading while in possession of material nonpublic information, and to avoid the appearance of any impropriety. These additional procedures are applicable only to those individuals described below.

Pre-Clearance Procedures: Directors, officers, accounting employees with the title of vice president or higher, investor relations employees that assist with earnings releases, legal department employees that assist with preparing SEC filings, any employees on the General Partner's disclosure committee, and any persons designated by the General Counsel as being subject to these procedures, as well as the Family Members and Controlled Entities of such persons ("Covered Senior Persons"), may not engage in any transaction in Partnership Securities without first obtaining pre-clearance of the transaction from the General Counsel. A request for pre-clearance should be submitted to the General Counsel at least two business days in advance of the proposed transaction. The General Counsel is under no obligation to approve a transaction submitted for pre-clearance, and may determine not to permit the transaction. If a person seeks pre-clearance and permission to engage in the transaction is denied, then he or she should refrain from initiating any transaction in Partnership Securities, and should not inform any other person of the restriction.

When a request for pre-clearance is made, the requestor should carefully consider whether he or she may be aware of any material nonpublic information about the Partnership, and should describe fully those circumstances to the General Counsel. The requestor should also indicate whether he or she has effected any non-exempt "opposite-way" transactions within the past six months, and should be prepared to report the proposed transaction on an appropriate Form 4 or Form 5. The requestor should also be prepared to comply with SEC Rule 144 and file Form 144, if applicable, at the time of any sale.

If a person seeks pre-clearance and permission to engage in the transaction is granted, then such trade must be effected within five business days of receipt of pre-clearance unless an exception is granted. Such person must promptly notify the General Counsel following the completion of the transaction. A person who has not effected a transaction within the time limit may not engage in such transaction without again obtaining pre-clearance of the transaction from the General Counsel.

<u>Quarterly Blackout Periods</u>: Covered Senior Persons may not conduct any transactions involving Partnership Securities (other than as specified by this Policy), during a "Blackout Period" beginning on the first day of each fiscal quarter and ending after the close of trading on the first full trading day following the date of the public release of the Partnership's earnings results for that quarter. In other words, these persons may only conduct transactions in Partnership Securities during the "Window Period" beginning after the close of trading on the first full trading day following the public release of the Partnership's quarterly earnings and ending immediately prior to the first day of the next fiscal quarter.

<u>Event-Specific Blackout Periods</u>: From time to time, an event may occur that is material to the Partnership and is known by only a few directors, officers and/or employees. So long as the event remains material and nonpublic, the persons designated by the General Counsel may not trade Partnership Securities. In addition, the Partnership's financial results may be sufficiently material in a particular fiscal quarter that, in the judgment of the General Counsel, designated persons should refrain from trading in Partnership Securities even sooner than the typical Blackout Period described above. In that situation, the General Counsel may notify these persons that they should not trade in Partnership Securities, without disclosing the reason for the restriction. The existence of an event-specific trading restriction period or extension of a Blackout Period will not be announced to the Partnership as a whole, and should not be communicated to any other person. Even if the General Counsel has not designated you as a person who should not trade due to an event-specific restriction, you should not trade while aware of material nonpublic information.

Exceptions. The quarterly trading restrictions and event-driven trading restrictions do not apply to those transactions to which this Policy does not apply, as described above under the headings “Transactions Under Partnership Plans and Certain Other Transactions.” Further, the requirement for pre-clearance, the quarterly trading restrictions and event-driven trading restrictions do not apply to transactions conducted pursuant to approved Rule 10b5-1 plans, described under the heading “Rule 10b5-1 Plans.”

RULE 10B5-1 PLANS

Rule 10b5-1 under the Exchange Act provides an affirmative defense to insider trading allegations under federal law. In order to be eligible to rely on this defense, a person subject to this Policy must enter into a Rule 10b5-1 plan for transactions in Partnership Securities that meets the conditions specified in the Rule (a “Rule 10b5-1 Plan”). If the plan meets the requirements of Rule 10b5-1, Partnership Securities may be purchased or sold without regard to certain insider trading restrictions described in this Policy.

To comply with the Policy, the adoption, modification or early termination of a Rule 10b5-1 Plan must be approved by the General Counsel, and all Rule 10b5-1 Plans must meet the requirements of Rule 10b5-1. Any Rule 10b5-1 Plan must be submitted for approval five days prior to the entry into the Rule 10b5-1 Plan, and any proposed modifications or terminations thereof must be submitted for approval at least three days prior to the consummation of such actions. No further pre-approval of transactions conducted pursuant to the Rule 10b5-1 Plan will be required.

In addition, a Rule 10b5-1 Plan may be entered into or modified only (i) at a time when the person entering into, or modifying the plan is not aware of material nonpublic information about the Partnership or Partnership Securities and (ii) in the case of Covered Senior Persons, during an open “Window Period.” Once the plan is adopted, the person must not exercise any influence over the amount of securities to be traded, the price at which they are to be traded or the date of the trade. The plan must either specify the amount, pricing and timing of transactions in advance or delegate discretion on these matters to an independent third party.

Once a Rule 10b5-1 Plan is pre-cleared and is adopted or modified, it is subject to a “cooling-off” period before execution of the first trade. The “cooling-off” period for directors and officers subject to Section 16 of the Exchange Act ends on the later of: (1) 90 days following the Rule 10b5-1 Plan adoption or modification or (2) two business days following the disclosure in Form 10-Q or Form 10-K of the Partnership’s financial results for the fiscal quarter in which the Rule 10b5-1 Plan was adopted or modified (however, the cooling-off period will not exceed 120 days following plan adoption or modification). For all other individuals, a 30 day cooling-off period is required.

A person may not enter into overlapping Rule 10b5-1 Plans (subject to certain exceptions) and may only enter into one single-trade Rule 10b5-1 Plan during any 12-month period (subject to certain exceptions). Directors and officers subject to Section 16 of the Exchange Act must include a representation in their Rule 10b5-1 Plan certifying that: (i) they are not aware of any material nonpublic information; and (ii) they are adopting the Rule 10b5-1 Plan in good faith and not as part of a plan or scheme to evade the prohibitions in Rule 10b-5.

All persons entering into a Rule 10b5-1 Plan must act in good faith with respect to that plan.

POST-TERMINATION TRANSACTIONS

This Policy continues to apply to transactions in Partnership Securities even after termination of service to the General Partner. If an individual is in possession of material nonpublic information when his or her service terminates, that individual may not trade in Partnership Securities until that information has become public or is no longer material. The pre-clearance procedures specified under the heading “Pre-Clearance and Blackouts” above, however, will cease to apply to transactions in Partnership Securities upon the expiration of any Blackout Period or other General Partner-imposed trading restrictions applicable at the time of the termination of service.

CONSEQUENCES OF VIOLATIONS

The purchase or sale of securities while aware of material nonpublic information, or the disclosure of material nonpublic information to others who then trade in Partnership Securities, is prohibited by federal and state laws. Insider trading violations are pursued vigorously by the SEC, U.S. Attorneys and state enforcement authorities as well as the laws of foreign jurisdictions.

Punishment for insider trading violations is severe, and could include significant fines and imprisonment. While the regulatory authorities concentrate their efforts on the individuals who trade, or who tip inside information to others who trade, the federal securities laws also impose potential liability on companies and other “controlling persons” if they fail to take reasonable steps to prevent insider trading by company personnel.

In addition, an individual’s failure to comply with this Policy may subject the individual to General Partner-imposed sanctions, including dismissal for cause, whether or not the employee’s failure to comply results in a violation of law. Needless to say, a violation of law, or even an SEC investigation that does not result in prosecution, can tarnish a person’s reputation and irreparably damage a career.

GENERAL PARTNER ASSISTANCE

Any person who has a question about this Policy or its application to any proposed transaction may obtain additional guidance from the General Counsel, who can be reached by e-mail at mreel@machresources.com.

Exhibit 21.1

SUBSIDIARIES OF MACH NATURAL RESOURCES LP

Name of Subsidiary	Jurisdiction of Organization
Mach Natural Resources Intermediate LLC	Delaware
Mach Natural Resources Holdco LLC	Delaware
BCE-Mach LLC	Delaware
BCE-Mach II LLC	Delaware
BCE-Mach III LLC	Delaware
BCE-Mach III Midstream Holdings LLC	Delaware
Simcoe LLC	Delaware
Simlog LLC	Delaware
SJ Investment Opps LLC	Delaware
Ringwood Gathering Company, LLC	Delaware
Timberland Gathering & Processing Company, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 12, 2026, with respect to the consolidated financial statements included in the Annual Report of Mach Natural Resources LP on Form 10-K for the year ended December 31, 2025. We consent to the incorporation by reference of said report in the Registration Statements of Mach Natural Resources LP on Form S-3 (File Nos. 333-291166, 333-283511, 333-290448) and on Form S-8 (File No. 333-275200).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 12, 2026

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to, and the inclusion of, (a) our summary reserve report dated January 15, 2026, and oil, natural gas and NGL reserves estimates and forecasts of economics as of December 31, 2025 and (b) our summary reserve report dated January 21, 2025, and oil, natural gas and NGL reserves estimates and forecasts of economics as of December 31, 2024, each included in or made part of this Annual Report on Form 10-K of Mach Natural Resources LP (the "Company"). We also consent to the incorporation by reference of such reports in the Registration Statement on Form S-3 (No. 333-283511) of the Company, Registration Statement on Form S-8 (No. 333-275200) of the Company, Registration Statement on Form S-3 (No. 333-290448) of the Company and Registration Statement on Form S-3 (No. 333-291166) of the Company, each filed with the U.S. Securities and Exchange Commission.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm

/s/ J. Zane Meekins

J. Zane Meekins, P.E.
Executive Vice President

Fort Worth, Texas
March 12, 2026

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers and geologists, we hereby consent to the references to our firm, in the context in which they appear, and to the references to, and the inclusion of, (a) our report dated January 15, 2026, with respect to estimates of proved reserves and future revenue, as of December 31, 2025, to the Mach Natural Resources LP (the Company) interest in certain gas properties located in Colorado and New Mexico, referred to as the San Juan Basin Properties, and (b) our report dated January 16, 2026, with respect to estimates of proved reserves and future revenue, as of December 31, 2025, to the Company interest in certain oil and gas properties located in New Mexico and Texas, referred to as the Permian Basin Properties, each included in or made part of this Annual Report on Form 10-K of the Company. We consent to the incorporation by reference of said reports in the Registration Statements of the Company on Form S-3 (File Nos. 333-291166, 333-283511, 333-290448) and on Form S-8 (File No. 333-275200).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.

Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

Houston, Texas
March 12, 2026

Exhibit 31.1

CERTIFICATION

I, Tom L. Ward, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mach Natural Resources LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 12, 2026

/s/ Tom L. Ward
Tom L. Ward
Chief Executive Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 31.2

CERTIFICATION

I, Kevin R. White, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mach Natural Resources LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 12, 2026

/s/ Kevin R. White
Kevin R. White
Chief Financial Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. § 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned officer of Mach Natural Resources LP (the "Company") hereby certifies, to such officer's knowledge, that:

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

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

Date: March 12, 2026

/s/ Tom L. Ward
Tom L. Ward
Chief Executive Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. § 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned officer of Mach Natural Resources LP (the “Company”) hereby certifies, to such officer’s knowledge, that:

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

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

Date: March 12, 2026

/s/ Kevin R. White
Kevin R. White
Chief Financial Officer
Mach Natural Resources GP, LLC, its general partner

Exhibit 99.1

Cawley, Gillespie & Associates, Inc.
PETROLEUM CONSULTANTS

6500 RIVER PLACE BLVD, BLDG 3 SUITE 200 306 WEST SEVENTH STREET, SUITE 302 1000 LOUISIANA STREET, SUITE 1900
AUSTIN, TEXAS 78730 FORT WORTH, TEXAS 76102-4905 HOUSTON, TEXAS 77002-5017
512-249-7000 817- 336-2461 713-651-9944
www.cgaus.com

January 15, 2026

Mr. Leighton Dilbeck
Director - Reservoir Engineering
Mach Natural Resources LP
14201 Wireless Way
Oklahoma City, OK 73134
Re: Evaluation Summary – SEC Pricing
Mach Natural Resources LP Interests
Various States
Proved Reserves
As of December 31, 2025
Dear Mr. Dilbeck:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the Mach Natural Resources LP ("Mach") interests in properties located in Oklahoma, Texas, Kansas, Arkansas and Wyoming. It is our understanding that the proved reserves estimated in this report constitute 100 percent of all proved reserves owned by Mach.

This report, completed on January 15, 2026, utilized an effective date of December 31, 2025, and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Proved Undeveloped	Proved
Net Reserves						
Oil	- Mbbl	41,706.5	331.5	0.0	13,329.5	55,367.4
Gas	- MMcf	938,680.2	6,227.5	0.0	282,692.8	1,227,600.6
NGL	- Mbbl	70,408.8	526.1	0.0	24,782.5	95,717.4
Revenue						
Oil	- M$	2,696,763.9	21,395.3	0.0	862,086.5	3,580,245.0
Gas	- M$	2,258,303.0	11,923.8	0.0	555,457.3	2,825,684.5
NGL	- M$	1,362,874.0	8,926.9	0.0	436,773.7	1,808,574.6
Severance and						
Ad Valorem Taxes	- M$	629,726.3	3,131.0	0.0	119,135.3	751,992.6
Operating Expenses	- M$	2,538,334.5	17,371.5	0.0	351,853.4	2,907,559.4
Investments	- M$	226,470.9	6,853.5	83,766.7	693,661.9	1,010,752.9
Operating Income (BFIT)	- M$	2,923,408.4	14,890.0	-83,766.7	689,666.9	3,544,200.7
Discounted at 10.0%	- M$	1,723,278.8	4,614.8	-13,688.6	173,955.4	1,888,160.1

We evaluated cases that comprise approximately 90% of the cumulative discounted cash flows of the proved developed producing reserves from the company's internal evaluation of the upstream cases and 100% of the reserves in the remaining categories. We refer to these cases as the "Major Upstream" properties, and composite reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Proved Undeveloped
Net Reserves					
Oil	- Mbbl	35,713.1	331.5	0.0	13,329.5
Gas	- MMcf	715,336.3	6,227.5	0.0	282,692.8
NGL	- Mbbl	56,649.2	526.1	0.0	24,782.5
Revenue					
Oil	- M$	2,313,177.1	21,395.3	0.0	862,086.5
Gas	- M$	1,247,183.2	11,923.8	0.0	534,197.4
NGL	- M$	1,050,051.3	8,926.9	0.0	436,773.7
Severance and					
Ad Valorem Taxes	- M$	334,900.9	3,131.0	0.0	119,135.3
Operating Expenses	- M$	1,348,001.0	17,371.5	0.0	354,914.7
Investments	- M$	56,018.8	6,853.5	83,766.7	693,661.9
Operating Income (BFIT)	- M$	2,871,490.8	14,890.0	-83,766.7	665,345.7
Discounted at 10.0%	- M$	1,484,296.6	4,614.8	-13,688.6	162,093.7

The remaining upstream cases are referred to as the "Minor Upstream" properties, and the company's internal reserve estimates and economic forecasts for these properties are summarized below:

		Minor Proved Developed Producing
Net Reserves		
Oil	- Mbbl	5,993.4
Gas	- MMcf	223,344.0
NGL	- Mbbl	13,759.6
Revenue		
Oil	- M$	383,586.8
Gas	- M$	415,691.1
NGL	- M$	265,398.5
Severance and		
Ad Valorem Taxes	- M$	83,357.2
Operating Expenses	- M$	544,580.8
Investments	- M$	170,452.1
Operating Income (BFIT)	- M$	266,285.6
Discounted at 10.0%	- M$	166,110.0

Composite forecasts of revenues and expenses for company-owned plants, gas gathering systems and water disposal systems are summarized below:

		Major Proved Developed Producing Midstream	Minor Proved Developed Producing Midstream	Proved Undeveloped Midstream	Total Proved Midstream
Net Reserves					
Oil	- Mbbl	0.0	0.0	0.0	0.0
Gas	- MMcf	0.0	0.0	0.0	0.0
NGL	- Mbbl	0.0	0.0	0.0	0.0
Revenue					
Oil	- M$	0.0	0.0	0.0	0.0
Gas	- M$	539,454.3	55,974.1	21,260.0	616,688.5
NGL	- M$	47,424.2	0.0	0.0	47,424.2
Severance and Ad Valorem Taxes	- M$	205,931.5	5,536.7	0.0	211,468.1
Operating Expenses	- M$	583,669.6	62,083.2	-3,061.3	642,691.4
Investments	- M$	0.0	0.0	0.0	0.0
Operating Income (BFIT)	- M$	-202,722.5	-11,645.7	24,321.3	-190,046.9
Discounted at 10.0%	- M$	70,584.4	2,287.0	11,861.7	84,733.0

The above revenues and expenses are limited to those associated only with Mach volumes. No revenues resulting from the gathering or processing of third party volumes are included. The minor proved developed producing revenues and expenses are from the company’s internal evaluation of the midstream cases.

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its “present worth”. The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $3.387 per MMBtu and the annual average WTI Cushing spot oil price of $65.34 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. NGL prices were forecast as fractions of the above SEC oil price. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the properties are $64.66 per barrel of oil, $2.30 per Mcf of gas, and $18.90 per barrel of NGL.

Operating expenses and capital costs were supplied by Mach and reviewed for reasonableness. Severance taxes and ad valorem taxes were forecast by state based on statutory rates or actual rates. Neither expenses nor investments were escalated. Net plugging costs were scheduled as $50,000 per well. The plugging costs for shut-in wells with no remaining reserves are captured in the proved developed shut-in category.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Mach Natural Resources LP. Ownership interests were supplied by Mach Natural Resources LP and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Cawley, Gillespie & Associates, Inc. is independent with respect to Mach Natural Resources LP as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

J. Zane Meekins, P.E.
Executive Vice President

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693
JZM:ptn

Exhibit 99.3

January 16, 2026

Mr. Leighton Dilbeck
Mach Natural Resources LP
14201 Wireless Way, Suite 300
Oklahoma City, Oklahoma 73134

Dear Mr. Dilbeck:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the Mach Natural Resources LP (Mach) interest in certain oil and gas properties located in New Mexico and Texas, referred to herein as the Permian Basin Properties. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 7 percent of all proved reserves owned by Mach. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Mach's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Mach interest in the Permian Basin Properties, as of December 31, 2025, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	48,175.8	1,850.7	4,897.8	1,204,975.7	601,227.3

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2025, there are no proved developed non-producing or proved undeveloped reserves for these properties. As requested, probable and possible reserves that may exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage.

Gross revenue is Mach's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Mach's share of production taxes, ad valorem taxes, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2025. For oil and NGL volumes, the average West Texas Intermediate spot price of $65.34 per barrel is adjusted by area for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.387 per MMBTU is adjusted by area for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $64.16 per barrel of oil, $22.70 per barrel of NGL, and $1.126 per MCF of gas.

Operating costs used in this report are based on operating expense records of Mach. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and Mach's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Abandonment costs used in this report are Mach's estimates of the costs to abandon the wells and production facilities; these estimates do not include any salvage value for the lease and well equipment. Abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Mach interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Mach receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Mach, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Matthew D. Pankey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2019 and has over 6 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ Matthew D. Pankey
Matthew D. Pankey, P.E. 142931
Vice President

Date Signed: January 16, 2026

MDP:ALA

January 15, 2026

Mr. Leighton Dilbeck
Mach Natural Resources LP
14201 Wireless Way, Suite 300
Oklahoma City, Oklahoma 73134

Dear Mr. Dilbeck:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the Mach Natural Resources LP (Mach) interest in certain gas properties located in Colorado and New Mexico, referred to herein as the San Juan Basin Properties. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 42 percent of all proved reserves owned by Mach. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Mach's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Mach interest in the San Juan Basin Properties, as of December 31, 2025, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Gas (MMCF)	Condensate (MBBL)	NGL (MBBL)	Total	Present Worth at 10%
Proved Developed Producing	1,226,593.1	655.7	18,007.5	1,057,437.4	561,211.3
Proved Undeveloped	450,746.0	0	0	327,514.2	38,747.6
Total Proved	1,677,339.1	655.7	18,007.5	1,384,951.6	599,958.8

Totals may not add because of rounding.

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Condensate and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2025, there are no proved developed non-producing reserves for these properties. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Mach's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Mach's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2025. For gas volumes, the average Henry Hub spot price of $3.387 per MMBTU is adjusted for energy content, transportation fees, and market differentials. As requested, an economic projection is included in the proved developed producing category to account for the effects of a fixed gas sales price contract in place through December 31, 2030. For condensate and NGL volumes, the average West Texas Intermediate spot price of $65.34 per barrel is adjusted for quality, transportation fees, and market differentials. The average adjusted product prices weighted by production over the remaining lives of the properties are $1.905 per MCF of gas, $54.38 per barrel of condensate, and $31.19 per barrel of NGL.

Operating costs used in this report are based on operating expense records of Mach. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and Mach's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by Mach and are based on internal planning estimates, authorizations for expenditure, and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Mach's estimates of the costs to abandon the wells and production facilities; these estimates do not include any salvage value for the lease and well equipment. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Mach interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Mach receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Mach, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Mach, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Joseph M. Mello, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2015 and has over 5 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ Joseph M. Mello
Joseph M. Mello, P.E. 125699
Vice President

Date Signed: January 15, 2026

JMM:EMM