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

Form 10-K

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

For the fiscal year ended December 31, 2024

OR

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

For the transition period from _________ to _________ .

Commission File Number: 001-35512

AMPLIFY ENERGY CORP.
(Exact name of registrant as specified in its charter)

Delaware	**82-1326219**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
500 Dallas Street, Suite 1700, Houston, TX	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(832) 219-9001**

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	AMPY	NYSE

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

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

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

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

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

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

Large accelerated filer	☐	Accelerated filer	☑
Non-accelerated filer	☐	Smaller reporting company	☑
Emerging growth company	☐		

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

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

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

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $202.1 million on June 30, 2024, based on $6.78 per share, the last reported sales price of the shares on the New York Stock Exchange on such date.

As of February 28, 2025, the registrant had 40,332,937 outstanding shares of common stock, $0.01 par value per share.

Documents Incorporated By Reference**:** Portions of the registrant's definitive proxy statement relating to its 2024 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2024, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Form 10-K.

AMPLIFY ENERGY CORP.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

3-D seismic: Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Analogous Reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

API Gravity: The American Petroleum Institute's system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

Basin: A large depression on the earth's surface in which sediments accumulate.

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

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

Boe/d: One Boe per day.

BOEM: Bureau of Ocean Energy Management.

BSEE: Bureau of Safety and Environmental Enforcement.

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one-degree Fahrenheit.

CO_2: Carbon dioxide.

Deterministic Estimate: The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed Acreage: The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Project: A development project is the means by which petroleum resources are brought to the status of economically producible. Examples include the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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.

Differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

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

Economically Producible: The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For this determination, the value of the products that generate revenue is determined at the terminal point of oil and natural gas producing activities.

Exploitation: A development or other project which may target proven or unproven reserves (such as probable or possible reserves) but which generally has a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend 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 and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

GAAP: Generally accepted accounting principles in the United States of America.

Gross Acres or ***Gross Wells***: The total acres or wells, as the case may be, in which we have a working interest.

ICE: Inter-Continental Exchange.

MBbl: One thousand Bbls.

MMBbls: One million stock tank barrels.

MBoe: One thousand barrels of oil equivalent.

MBoe/d: One thousand barrels of oil equivalent per day.

MMBoe: One million barrels of oil equivalent.

Mcf: One thousand cubic feet of natural gas.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent.

Net Acres or ***Net Wells***: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

Net Production: Production that is owned by us less royalties and production due others.

Net Revenue Interest: A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs: The combination of ethane, propane, butane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

NYSE: New York Stock Exchange.

Oil: Oil and condensate.

Operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Plugging and abandonment*:* Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues or ***PV-9***: The estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 9% in accordance with the guidelines of the SEC.

Present value of future net revenues or ***PV-10***: The estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

Probabilistic Estimate: The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrences.

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: 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. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration, unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation, and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves that can be produced economically through application of improved recovery techniques (including fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves ("PUDs"): Proved oil and natural gas 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Realized Price: The cash market price less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reliable Technology: Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserve Life: A measure of the productive life of an oil and natural gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year end by production volumes. In our calculation of reserve life, production volumes are adjusted, if necessary, to reflect property acquisitions and dispositions.

Reserves: Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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 reserves.

Resources: Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

SEC: The U.S. Securities and Exchange Commission.

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Standardized Measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules, regulations or standards established by the SEC and the Financial Accounting Standards Board ("FASB") (using prices and costs in effect as of the date of estimation), less estimated future development, production and income tax expenses and discounted at 10% per annum to reflect the timing of future net revenue. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in our oil and natural gas properties. Standardized measure does not give effect to derivative transactions.

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 or natural gas production on a completed well. Also called well or borehole.

Working Interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and generally requires the owner to pay a share of the costs of drilling and production operations.

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

WTI: West Texas Intermediate.

NAMES OF ENTITIES

As used in this 2024 Annual Report on Form 10-K (this "Annual Report"), unless we indicate otherwise:

- "Amplify Energy," "Company," "we," "our," "us," or like terms refers to Amplify Energy Corp. (f/k/a Midstates Petroleum Company, Inc.) individually and collectively with its subsidiaries, as the context requires;

- "Legacy Amplify" refers to Amplify Energy Holdings LLC (f/k/a Amplify Energy Corp.), the successor reporting company of Memorial Production Partners LP; and

- "OLLC" refers to Amplify Energy Operating LLC, the Company's wholly owned subsidiary through which it operates its properties.

FORWARD–LOOKING STATEMENTS

This Annual Report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategies;
- acquisition and disposition strategy;
- cash flows and liquidity;
- financial strategy;
- ability to replace the reserves we produce through drilling;
- drilling locations;
- oil and natural gas reserves;
- technology;
- realized oil, natural gas and NGL prices;
- production volumes;
- lease operating expense;
- gathering, processing and transportation;
- general and administrative expense;
- future operating results;
- ability to procure drilling and production equipment;
- ability to procure oil field labor;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- ability to access capital markets;
- marketing of oil, natural gas and NGLs;
- 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;
- acts of God, fires, earthquakes, storms, floods, other adverse weather conditions, war, acts of terrorism, cybersecurity breaches, military operations or national emergency;
- the occurrence or threat of epidemic or pandemic diseases, or any government response to such occurrence or threat;
- expectations regarding general economic conditions, including inflation;

- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- expectations regarding governmental regulation and taxation;
- expectations regarding developments in oil-producing and natural-gas producing countries; and
- plans, objectives, expectations and intentions.

All statements, other than statements of historical fact, included in this report are forward-looking statements. These forward-looking statements may be found in "Item 1. Business," "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report. In some cases, you can identify forward-looking statements by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "outlook," "continue," the negative of such terms or other comparable terminology. These statements address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as projections of results of operations, plans for growth, goals, future capital expenditures, competitive strengths, references to future intentions and other such references. These forward-looking statements involve risks and uncertainties. Important factors that could cause the Company's actual results or financial condition to differ materially from those expressed or implied by forward-looking statements include, but are not limited to, the following risks and uncertainties:

- the Company's ability to successfully complete the proposed business combination transaction between certain of the Company's subsidiaries and North Peak Oil & Gas, LLC and Century Oil and Gas Sub-Holdings, LLC (the "Mergers");
- risks related to a redetermination of the borrowing base under the Company's senior secured reserve-based revolving credit facility (the "Revolving Credit Facility");
- the Company's ability to access funds on acceptable terms, if at all, because of the terms and conditions governing its indebtedness, including financial covenants;
- the Company's ability to satisfy its debt obligations;
- volatility in the prices for oil, natural gas and NGLs;
- the potential for additional impairments due to continuing or future declines in oil, natural gas and NGL prices;
- the uncertainty inherent in estimating quantities of oil, natural gas and NGL reserves;
- the Company's substantial future capital requirements, which may be subject to limited availability of financing;
- the uncertainty inherent in the development and production of oil and natural gas;
- the Company's need to make accretive acquisitions or substantial capital expenditures to maintain its declining asset base;
- the existence of unanticipated liabilities or problems relating to acquired or divested businesses or properties;
- potential acquisitions, including the Company's ability to make acquisitions on favorable terms or to integrate acquired properties;
- the consequences of changes the Company has made, or may make from time to time in the future, to its capital expenditure budget, including the impact of those changes on its production levels, reserves, results of operations and liquidity;

- potential shortages of, or increased costs for, drilling and production equipment and supply materials for production, such as CO_2;
- potential difficulties in the marketing of oil and natural gas;
- changes to the financial condition of counterparties;
- uncertainties surrounding the success of the Company's secondary and tertiary recovery efforts;
- competition in the oil and natural gas industry;
- the Company's results of evaluation and implementation of strategic alternatives;
- general political and economic conditions, globally and in the jurisdictions in which we operate, including the Russian invasion of Ukraine and ongoing conflicts in the Middle East, and the potential destabilizing effect such conflicts may pose for those regions and/or the global oil and natural gas markets;
- the impact of climate change and natural disasters, such as earthquakes, tidal waves, mudslides, fires and floods;
- the impact of local, state and federal governmental regulations, including those related to climate change and hydraulic fracturing, and the current administration's potential reversal thereof;
- the risk that the Company's hedging strategy may be ineffective or may reduce our income;
- the cost and availability of insurance as well as operating risks that may not be covered by an effective indemnity or insurance;
- actions of third-party co-owners of interest in properties in which we also own an interest; and
- other risks and uncertainties described in "Item 1A. Risk Factors."

The forward-looking statements contained in this report are largely based on our expectations, which reflect estimates and assumptions made by the Company's management. These estimates and assumptions reflect the Company's best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond the Company's control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events or circumstances described in any forward-looking statement will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in "Item 1A. Risk Factors" and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on the Company's behalf.

RISK FACTOR SUMMARY

Our business is subject to numerous risks and uncertainties, including those highlighted in this section titled “Risk Factors” and summarized below. We have various types of risks, including risks related to our business and industry; information technology, data security and privacy; legal, regulatory, accounting, and tax matters; our common stock; and our Revolving Credit Facility, which are discussed more fully elsewhere in this Annual Report. As a result, this risk factor summary does not contain all of the information that may be important to you, and you should read this risk factor summary together with the more detailed discussion of risks and uncertainties set forth following this section under the heading “Risk Factors,” as well as elsewhere in this Annual Report. These risks include, but are not limited to, the following:

- Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and greatly affect our business, results of operations and financial condition. Any decline in, or sustained low levels of oil, natural gas and NGL prices will cause a decline in our cash flow from operations, which could materially and adversely affect our business, results of operations and financial condition.

- If commodity prices decline for a prolonged period, a significant portion of our development projects may become uneconomic and result in write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and our ability to fund our operations.

- We are currently involved in, and anticipate that we will continue to explore, opportunities to create value through strategic transactions, whether through mergers and acquisitions, divestitures, joint ventures or similar business transactions. There are risks inherent in any strategic transaction, including the Mergers, and such risks could negatively affect the benefits, outcomes and synergies anticipated to be obtained from executing such strategic transactions.

- Our business could be adversely affected by a decline in general economic conditions or a weakening of the broader energy industry, and inflation may adversely affect our financial position and operating results.

- We may be unable to maintain compliance with the covenants in the Revolving Credit Facility, which could result in an event of default thereunder that, if not cured or waived, would have a material adverse effect on our business and financial condition.

- Restrictive covenants in our Revolving Credit Facility could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

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

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

- The failure to replace our proved oil and natural gas reserves could adversely affect our business, financial condition, results of operations, production and cash flows.

- Many of our properties are in areas that may have been partially depleted or drained by offset wells.

- Our expectations for future development activities are planned to be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

- The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

- We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

- We may be subject to increased permitting obligations and regulatory scrutiny as a result of the oil incident that occurred in federal waters off the coast of Southern California related to the Company’s pipeline operations at the Beta field (the “Incident”).

- We expect to refinance substantial indebtedness of the Acquired Companies (as defined below) in connection with the Mergers, which combined with our current debt may limit our financial flexibility and adversely affect our financial results.

PART I

ITEM 1. BUSINESS

References

Amplify Energy Corp. ("Amplify Energy," the "Company," "we," "us," "our," or similar terms), is a publicly traded Delaware corporation, in which our common stock, par value of $0.01 per share ("Common Stock"), is listed on the NYSE under the symbol "AMPY."

Overview

Amplify Energy is an independent oil and natural gas company engaged in the acquisition, development, exploitation and production of oil and natural gas properties. Our management evaluates performance based on one reportable business segment, as the economic environments are not different within the operation of our oil and natural gas properties. Our business activities are conducted through OLLC, our wholly owned subsidiary, and its wholly owned subsidiaries. Our assets consist primarily of producing oil and natural gas properties located in Oklahoma, the Rockies ("Bairoil"), federal waters offshore Southern California ("Beta"), East Texas/North Louisiana, and Eagle Ford (Non-op). Most of our oil and natural gas properties are located in large, mature oil and natural gas reservoirs.

The Company's properties consist primarily of operated and non-operated working interests in producing and undeveloped leasehold acreage and working interests in identified producing wells. As of December 31, 2024:

- Our total estimated proved reserves were approximately 93.0 MMBoe, consisting of approximately 44% oil, 37% natural gas, and 19% NGLs, and 88% were classified as proved developed reserves;

- We produced oil and natural gas from 2,523 gross (1,353 net) producing wells across our properties, with an average working interest of 54%, and we are the operator of record of the properties containing 92% of our total estimated proved reserves; and

- Our average net production for the three months ended December 31, 2024, was 18.5 MBoe/d, implying a reserve-to-production ratio of approximately 13.8 years.

Recent Developments

East Texas Haynesville Monetization

In December 2024, we sold certain rights, title and interest in assets located in East Texas to a third party. We recorded a gain of approximately $1.4 million.

In January 2025, we purchased and sold certain rights, title and interest in assets in East Texas from a third party, whereby we received net proceeds of $6.2 million.

Merger with Juniper Capital

On January 14, 2025, we entered into an Agreement and Plan of Merger (the "Merger Agreement") with Amplify DJ Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of the Company ("First Merger Sub"), Amplify PRB Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of Amplify ("Second Merger Sub," and together with First Merger Sub, the "Merger Subs"), North Peak Oil & Gas, LLC, a Delaware limited liability company ("NPOG"), Century Oil and Gas Sub-Holdings, LLC, a Delaware limited liability company ("COG" and, together with NPOG, each, an "Acquired Company" and, collectively, the "Acquired Companies"), and, solely for the limited purposes set forth in the Merger Agreement (as defined below), Juniper Capital Advisors, L.P., a Delaware limited partnership ("Juniper"), and the Specified Company Entities set forth on Annex A thereto, pursuant to which, at the effective time of the Mergers (as defined below) (the "Effective Time"), (a) NPOG will merge with and into First Merger Sub, with NPOG surviving the merger as an indirect, wholly owned subsidiary of the Company and (b) COG will merge with and into Second Merger Sub, with COG surviving the merger as an indirect, wholly owned subsidiary of the Company, in each case, subject to the terms and conditions of the Merger Agreement.

Subject to the terms and conditions of the Merger Agreement, at the Effective Time, all of the issued and outstanding limited liability company interests of each of the Acquired Companies will automatically be converted into the right to receive, in the aggregate, 26,729,315 validly issued, fully paid and nonassessable shares (the "Aggregate Merger Consideration") of Common Stock. Following the Effective Time, the Company's existing stockholders and the Acquired Companies' existing equityholders are expected to own approximately 61% and 39%, respectively, of the combined company's outstanding equity.

Mr. Christopher W. Hamm will serve as Chairman of our board of directors (the "Board"), and Mr. Martyn Willsher will continue to serve as the Chief Executive Officer of the Company after the Effective Time. The Merger Agreement provides that the Board will consist of the following seven members: Martyn Willsher, Christopher W. Hamm, Deborah G. Adams, James E. Craddock, Vidisha Prasad, Edward Geiser and Josh Schmidt. Further, Josh Schmidt will be appointed as Chairman of the compensation committee of the Board (the "Compensation Committee"), and Edward Geiser will be appointed as a member of the nominating and governance committee of the Board (the "Nominating & Governance Committee").

The Merger Agreement contains customary representations, warranties and covenants of the Company and the Acquired Companies, including covenants relating to the conduct of the business of both the Company and the Acquired Companies from the date of signing the Merger Agreement through closing of the Mergers (the "Closing"), obtaining the requisite approval of the stockholders of the Company and maintaining the listing of the Common Stock on the NYSE. Under the terms of the Merger Agreement, the Company has also agreed not to solicit from any person an acquisition proposal for the Company.

In connection with the Mergers, the Company will seek the approval of the Company's stockholders with respect to the issuance of the Aggregate Merger Consideration in connection with the Closing (the "Stock Issuance Proposal").

The Mergers are expected to close in the second quarter of 2025.

No Offer or Solicitation. This section of the Annual Report relates to a proposed business combination transaction between the Company and the Acquired Companies. This communication is for informational purposes only and does not constitute an offer to sell or the solicitation of an offer to buy any securities or a solicitation of any vote or approval, in any jurisdiction, pursuant to the business combination transaction or otherwise, nor shall there be any sale, issuance, exchange or transfer of the securities referred to in this document in any jurisdiction in contravention of applicable law. No offer of securities shall be made except by means of a prospectus meeting the requirements of Section 10 of the Securities Act of 1933, as amended.

Important Additional Information Regarding the Mergers Will Be Filed With the SEC. In connection with the proposed Mergers, the Company has filed a definitive proxy statement. The definitive proxy statement will be sent to the stockholders of the Company. The Company may also file other documents with the SEC regarding the Mergers. INVESTORS AND SECURITY HOLDERS OF AMPLIFY ENERGY ARE ADVISED TO CAREFULLY READ THE DEFINITIVE PROXY STATEMENT AND ANY OTHER RELEVANT MATERIALS FILED WITH THE SEC WHEN THEY BECOME AVAILABLE BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT THE MERGERS, THE PARTIES TO THE MERGERS AND THE RISKS ASSOCIATED WITH THE MERGERS. Investors and security holders may obtain a free copy of the definitive proxy statement and other relevant documents filed by Amplify Energy with the SEC from the SEC's website at www.sec.gov. Security holders and other interested parties will also be able to obtain, without charge, a copy of the definitive proxy statement and other relevant documents (when available) by (1) directing your written request to: 500 Dallas Street, Suite 1700, Houston, Texas or (2) contacting our Investor Relations department by telephone at (832) 219-9044 or (832) 219-9051. Copies of the documents filed by the Company with the SEC will be available free of charge on the Company's website at http://www.amplifyenergy.com.

Participants in the Solicitation. Amplify Energy and certain of its respective directors, executive officers and employees may be considered participants in the solicitation of proxies in connection with the proposed transaction. Information regarding the persons who may, under the rules of the SEC, be deemed participants in the solicitation of the stockholders of Amplify Energy in connection with the transaction, including a description of their respective direct or indirect interests, by security holdings or otherwise, is included in the definitive proxy statement filed with the SEC. Additional information regarding the Company's directors and executive officers is also included in Amplify's Notice of Annual Meeting of Stockholders and 2024 Proxy Statement, which was filed with the SEC on April 5, 2024. These documents are available free of charge as described above.

Industry Trends

We continue to monitor the impact of the actions of the Organization of the Petroleum Exporting Countries and other large producing nations; the Russia-Ukraine conflict; conflicts in the Middle East; global inventories of oil and natural gas and the uncertainty associated with recovering oil demand; inflation and future monetary policy; and governmental policies aimed at transitioning towards lower carbon energy. The Russia-Ukraine conflict and conflicts in the Middle East continue to evolve, and the extent to which these events may impact our business, results of operations, financial condition and cash flows will depend on future developments, which are highly uncertain and cannot be predicted with confidence.

Properties

We engaged Cawley, Gillespie and Associates, Inc. ("CG&A"), our independent reserve engineers, to prepare our reserves estimates for all of our proved reserves at December 31, 2024. The following table summarizes information, based on a reserve report prepared by CG&A (which we refer to as our "reserve report"), about our proved oil and natural gas reserves by geographic region as of December 31, 2024, and our average net production for the three months ended December 31, 2024:

	Estimated Net Proved Reserves				Average Net Production			Producing Wells	
Region	MMBoe (1)	% Oil and NGL	% Natural Gas	% Proved Developed	MBoe/d	% of Total	Average Reserve-to Production Ratio (2) (Years)	Gross	Net
Oklahoma	27.0	46 %	54 %	100 %	4.7	26 %	15.6	373	275
Bairoil	16.4	100 %	— %	100 %	3.2	17 %	14.1	152	152
Beta	19.1	100 %	— %	56 %	3.3	18 %	15.8	51	51
East Texas/ North Louisiana	28.0	30 %	70 %	94 %	6.6	36 %	11.6	1,546	850
Eagle Ford	2.5	90 %	10 %	69 %	0.7	4 %	10.2	401	25
Total	93.0	63 %	37 %	88 %	18.5	100 %	13.8	2,523	1,353

(1) Determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) The average reserve-to-production ratio is calculated by dividing estimated net proved reserves as of December 31, 2024 by the annualized average net production for the three months ended December 31, 2024.

Our Areas of Operation

Oklahoma

Approximately 29% of our estimated proved reserves as of December 31, 2024 and approximately 26% of our average daily net production for the three months ended December 31, 2024 were located in the Oklahoma region. Our Oklahoma properties include wells and properties primarily located in Alfalfa and Woods counties in Oklahoma. Those properties collectively contained 27.0 MMBbls of estimated net proved reserves as of December 31, 2024 based on our reserve report and generated average net production of 4.7 MBoe/d for the three months ended December 31, 2024.

Bairoil

Approximately 18% of our estimated proved reserves as of December 31, 2024 and approximately 17% of our average daily net production for the three months ended December 31, 2024 were located in Bairoil. Our Bairoil properties include wells and properties primarily located in the Lost Soldier and Wertz fields in Wyoming at our Bairoil complex. Our Bairoil properties contained 16.4 MMBbls of estimated net proved oil and NGLs reserves as of December 31, 2024 based on our reserve report and generated average net production of 3.2 MBoe/d for the three months ended December 31, 2024.

Beta

Approximately 20% of our estimated proved reserves as of December 31, 2024 and approximately 18% of our average daily net production for the three months ended December 31, 2024 were associated with the Beta field located in federal waters approximately 11 miles offshore from the Port of Long Beach, California. Our ownership in Beta consists of 100% of the working interests and 75.2% average net revenue interest in three Pacific Outer Continental Shelf lease blocks (P-0300, P-0301 and P-0306) (referred to as the "Beta Unit") in the Beta field. The Beta properties contained 19.1 MMBbls of estimated net proved oil reserves as of December 31, 2024 based on our reserve report and generated average net production of 3.3 MBoe/d for the three months ended December 31, 2024. Oil and gas are produced from the Beta Unit via two production platforms, referred to as the Ellen and Eureka platforms, equipped with permanent drilling rigs and associated equipment. On a third platform, Elly, the oil, water and gas are separated, and the oil is prepared for sale, while the gas is utilized as fuel for power and the water is recycled back into the reservoir for pressure maintenance. Sales quality oil is then pumped from the Elly platform to the Beta pump station located onshore at the Port of Long Beach, California via a 16-inch diameter oil pipeline, which extends approximately 17.5 miles. Amplify Energy's wholly owned subsidiary, San Pedro Bay Pipeline Company owns and operates the pipeline system.

Based on our reserve report, the Beta field contains more than 15% of our total estimated reserves as of December 31, 2024. The following table summarizes production volumes from this field for the period presented:

	December 31,	
	2024	2023
Production Volumes [1]:		
Oil (MBbls)	1,170	679
NGLs (MBbls)	—	—
Natural Gas (MMcfe)	—	—
Total (MBoe)	1,170	679
Average net production (MBoe/d)	3.2	1.9

(1) The Beta field restarted production in April 2023.

East Texas / North Louisiana

Approximately 30% of our estimated proved reserves as of December 31, 2024 and approximately 36% of our average daily net production for the three months ended December 31, 2024 were located in the East Texas/ North Louisiana region. Our East Texas/ North Louisiana properties include wells and properties primarily located in the Joaquin, Carthage, Willow Springs and East Henderson fields in East Texas. Those properties collectively contained 28.0 MMBoe of estimated net proved reserves as of December 31, 2024 based on our reserve report and generated average net production of 6.6 MBoe/d for the three months ended December 31, 2024.

Eagle Ford

Approximately 3% of our estimated proved reserves as of December 31, 2024 and approximately 4% of our average daily net production for the three months ended December 31, 2024 were located in the Eagle Ford region. Our Eagle Ford properties include wells and properties in fields located primarily in the Eagleville fields. Our Eagle Ford properties contained 2.5 MMBoe of estimated net proved reserves as of December 31, 2024 based on our reserve report. Those properties collectively generated average net production of 0.7 MBoe/d for the three months ended December 31, 2024.

Our Oil and Natural Gas Data

Our Reserves

Internal Controls. Our proved reserves were estimated at the well or unit level for reporting purposes by CG&A, our independent reserve engineers. We maintain internal evaluations of our reserves in a secure reserve engineering database. CG&A interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting, and marketing employees to obtain the necessary data to prepare our proved reserves report. Reserves are reviewed and approved internally by our senior management on an annual basis and evaluated by our lender group on at least a semi-annual basis in connection with borrowing base redeterminations under our Revolving Credit Facility. Our reserve estimates are prepared by CG&A at least annually.

Our internal professional staff works closely with CG&A to ensure the integrity, accuracy and timeliness of data that is furnished to them in order to prepare the reserves report. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide CG&A with other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their preparation of our reserves.

Qualifications of Responsible Technical Persons

Internal Engineers. Tony Lopez is the technical person at the Company, primarily responsible for overseeing and providing oversight of the preparation of the reserves estimates with our third-party reserve engineers.

Mr. Lopez has over 17 years of corporate reserve reporting experience. Mr. Lopez joined the Company as Vice President of Corporate Reserves in June 2018 and currently serves as the Company's Senior Vice President of Engineering & Exploitation. Prior to that Mr. Lopez was Vice President of Acquisitions and Engineering for EnerVest, Ltd., where he managed the corporate reserve reporting process and the financial planning & analysis department. Mr. Lopez is a graduate of West Virginia University and holds a B.S. in Petroleum and Natural Gas Engineering. Mr. Lopez is an active member of the Society of Petroleum Engineers.

Cawley, Gillespie and Associates Inc. CG&A is an independent oil and natural gas consulting firm. No director, officer, or key employee of CG&A has any financial ownership in us or any of our affiliates. CG&A's compensation for the preparation of its report is not contingent upon the results obtained and reported. CG&A has not performed other work for us or any of our affiliates that would affect its objectivity. The estimates of our proved reserves presented in the CG&A reserve report were overseen by Todd Brooker.

Mr. Brooker became the President of CG&A in 2017 and has been an employee of CG&A since 1992. His responsibilities include reserve and economic evaluations, fair market valuations, field studies, pipeline resource studies and acquisition/divestiture analysis. His reserve reports are routinely used for public company SEC disclosures. Prior to joining CG&A, Mr. Brooker worked in Gulf of Mexico drilling and production engineering at Chevron Corporation. Mr. Brooker's experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures.

Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Estimated Proved Reserves

The following table summarizes our estimated proved oil and natural gas reserves and related standardized measure of discounted future net cash flows attributable to our properties as of December 31, 2024, which are based on the prepared reserve report by CG&A, our independent reserve engineers.

	Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe) (1)
Estimated Proved Reserves				
Developed	31,392	197,621	17,879	82,207
Undeveloped	9,083	8,915	187	10,756
Total	40,475	206,536	18,066	92,963
Proved developed reserves as a percentage of total proved reserves				88 %
Standardized measure (in thousands) (2)				$ 608,239
PV-10 (in thousands) (3)				$ 735,765
Oil and Natural Gas Prices (4)				
Oil – WTI ($ per Bbl)				$ 75.48
Natural gas – Henry Hub ($ per MMBtu)				$ 2.13

(1) Determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Standardized measure is calculated in accordance with Accounting Standards Codification, or ASC, Topic 932, *Extractive Activities—Oil and Gas*, and is calculated using SEC pricing, before market differentials, of $75.48 per Bbl for crude oil and NGLs and $2.13 per MMBtu for natural gas. Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest expense, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions. For a description of our commodity derivative contracts, see “Item 1. Business — Operations — Derivative Activities” as well as “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Commodity Derivative Contracts.”

(3) PV-10 is a non-GAAP financial measure and represents the year end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC prescribed pricing assumptions for the period. PV-10 differs from standardized measure because standardized measure includes the effects of future income taxes on future net cash flows. Standardized measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing costs and discount assumptions. Amplify believes the presentation of PV-10 provides useful information because it is widely used by investors in evaluating oil and natural gas companies without regard to specific income tax characteristics of such entities. PV-10 is not intended to represent the current market value of our estimated proved reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(4) Our estimated net proved reserves and related standardized measure were determined using 12-month trailing average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month in effect as of the date of the estimate, without giving effect to derivative contracts, held constant throughout the life of the properties. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

The data in the table above represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate standardized measure, which is required by the SEC and FASB, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. For these reasons, neither standardized measure nor PV-10 should be construed as the fair value of our oil and natural gas reserves.

For a discussion of risks associated with internal reserve estimates, see “Item 1A. Risk Factors — Risks Related to Our Business — Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.”

Development of Proved Undeveloped Reserves

As of December 31, 2024, we had 10,756 MBoe of PUDs, comprised of 9,083 MBbls of oil, 8,915 MMcf of natural gas and 187 MBbls of NGLs. None of our PUDs as of December 31, 2024 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

For the year ended December 31, 2024, total PUDs increased by 8,830 MBoe. The increase includes 9,390 MBoe due to the addition of 23 Beta PUD locations, 4 non-operated PUDs in East Texas drilled and waiting on completion, and 4 non-operated Eagle Ford PUDs drilled and waiting on completion. We also had transfers of (524) MBoe to proved developed reserves as a result of the 2024 Beta drilling program. We removed 7 Eagle Ford PUDs (162) MBoe, due to the extension of the development plan beyond five years. Other revisions consisted of 126 MBoe that were primarily related to Beta PUD performance.

Approximately 27.2% (524 MBoe) of our PUDs recorded as of December 31, 2024 were developed during the twelve months ended December 31, 2024. Total costs incurred in 2024 to develop these PUDs were approximately $10.9 million. In total, we incurred total capital expenditures of approximately $30.7 million during fiscal year 2024 developing PUDs, which includes $19.8 million associated with PUDs to be completed in 2025. Based on our current expectations of our cash flows, we believe that we can fund the drilling of our current PUD inventory and our expansions in the next five years from our cash flow from operations and borrowings under our Revolving Credit Facility. For a more detailed discussion of our liquidity position, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources.”

Production, Revenue and Price History

For a description of our production, revenues, and average sales prices and per unit costs, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations.”

The following tables summarize our average net production, average unhedged sales prices by product and average lease operating cost expense per Boe by geographic region for the years ended December 31, 2024 and 2023, respectively:

	For the Year Ended December 31, 2024								
	Oil		NGLs		Natural Gas		Total		
	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MMcf)	Average Sales Price ($/Mcf)	Production Volumes (MBoe)	Average Sales Price ($/Boe)	Lease Operating Expense ($/Boe)
Oklahoma	347	$ 75.05	525	$ 23.07	5,995	$ 2.06	1,871	$ 26.98	$ 8.53
Bairoil	1,181	70.01	—	—	—	—	1,181	70.01	44.70
Beta	1,170	72.51	—	—	—	—	1,170	72.51	38.94
East Texas/ North Louisiana	143	73.38	717	19.48	10,627	2.17	2,631	18.07	8.59
Eagle Ford	219	74.50	36	19.79	214	2.01	291	60.00	20.72
Total	3,060	$ 72.01	1,278	$ 20.96	16,836	$ 2.13	7,144	$ 39.61	$ 20.01
Average net production (MBoe/d)							19.5		

	For the Year Ended December 31, 2023								
	Oil		NGLs		Natural Gas		Total		
	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MMcf)	Average Sales Price ($/Mcf)	Production Volumes (MBoe)	Average Sales Price ($/Boe)	Lease Operating Expense ($/Boe)
Oklahoma	426	$ 76.14	602	$ 21.48	6,706	$ 2.95	2,145	$ 30.36	$ 9.25
Bairoil	1,199	72.15	—	—	—	—	1,199	72.15	41.34
Beta (1)	679	75.31	—	—	—	—	679	75.31	57.02
East Texas/ North Louisiana	157	75.05	681	23.08	13,359	2.46	3,065	19.67	8.12
Eagle Ford	312	76.29	40	19.47	232	2.52	391	64.44	16.82
Total	2,773	$ 74.17	1,323	$ 22.24	20,297	$ 2.62	7,479	$ 38.54	$ 18.66
Average net production (MBoe/d)							20.5		

(1) The Beta field restarted production in April 2023.

Productive Wells

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest and net wells are the sum of our fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2024.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Operated (1)	516	475	914	770
Non-operated	495	40	598	68
Total	1,011	515	1,512	838

(1) Our operated properties reflect all operated proved devolved producing properties at December 31, 2024.

Developed Acreage

Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2024, substantially all of our leasehold acreage was held by production. The following table sets forth information as of December 31, 2024 relating to our leasehold acreage.

Region	Developed Acreage (1)	
	Gross (2)	Net (3)
Oklahoma	111,581	93,984
Bairoil	6,653	6,653
Beta	17,280	17,280
East Texas/ North Louisiana	243,101	181,460
Eagle Ford	14,167	811
Total	392,782	300,188

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.
(2) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.
(3) A net acre is deemed to exist when the sum of our fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

As of December 31, 2024, we had no gross and net undeveloped acreage expiring over the next two years as all of our gross and net acreage is currently held by production.

Drilling Activities

Our drilling activities primarily consist of development wells. The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2024, we had 24 gross (3.8 net) wells that were in various stages of completion.

	For the Year Ended December 31,			
	2024		2023	
	Gross	Net	Gross	Net
Development wells:				
Productive	11.0	2.0	9.0	0.5
Dry	—	—	—	—
Exploratory wells:				
Productive	—	—	—	—
Dry	—	—	—	—
Total wells:				
Productive	11.0	2.0	9.0	0.5
Dry	—	—	—	—
Total	11.0	2.0	9.0	0.5

Delivery Commitments

We have no commitments to deliver a fixed and determinable quantity of our oil or natural gas production in the near future under our existing sales contracts.

Operations

General

As of December 31, 2024, the Company is the operator of record of properties containing 92% of our total estimated proved reserves. We design and manage the development, recompletion and/or workover operations, and supervise other operation and maintenance activities for all of the wells we operate. We do not own the drilling rigs used for drilling wells on our onshore properties; independent contractors provide all the equipment and personnel associated with these activities. Our Beta platforms have permanent drilling systems in place.

Marketing and Major Customers

The following individual customers each accounted for 10% or more of our total reported revenues for the period indicated:

	For the Year Ended December 31,	
	2024	2023
Major customers:		
Phillips 66	33 %	17 %
HF Sinclair Corporation (formerly: Sinclair Oil & Gas Company)	25 %	24 %
Southwest Energy LP	10 %	13 %

The production sales agreements covering our properties contain customary terms and conditions for the oil and natural gas industry and provide for sales based on prevailing market prices. A majority of those agreements have terms that renew on a month-to-month basis until either party gives advance written notice of termination.

If we were to lose any one of our customers, the loss could temporarily delay production and sale of a portion of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes. However, if one or more of our larger customers ceased purchasing oil or natural gas altogether and we were unable to replace them, the loss of any such customer could have a detrimental effect on our production volumes and revenues in general.

In October 2024, Phillips 66 announced its plan to cease operations at its Los Angeles area refinery in the fourth quarter of 2025. This refinery has historically represented a significant portion of our sales to Phillips 66. We are actively engaging in discussions with Phillips 66 to understand the full scope of the impact on our business. While the closure of this refinery has the potential to materially affect our future sales to this customer, we anticipate that a commercial agreement will be reached with another customer to purchase our California crude oil. The inability to obtain such agreement or to obtain an agreement with less favorable terms than the current agreement with Phillips 66 could negatively impact our revenue, earnings and cash from operating activities.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with industry standards. More thorough title investigations are customarily made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under natural gas leases, or net profits interests.

Derivative Activities

We enter into commodity derivative contracts with unaffiliated third parties, generally lenders under our Revolving Credit Facility or their affiliates, to achieve more predictable cash flows and to reduce our exposure to fluctuations in oil and natural gas prices. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 50% − 75% of our estimated production from total proved developed producing reserves over a one-to-three-year period at any given point of time. We may, however, from time to time, hedge more or less than this approximate amount.

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those in our Revolving Credit Facility) to fixed interest rates.

It is our policy to enter into derivative contracts only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our Revolving Credit Facility are counterparties to our derivative contracts. We will continue to evaluate the benefit of employing derivatives in the future.

Competition

We operate in a highly competitive environment for acquiring properties, leasing acreage, contracting for drilling equipment and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry and many of our competitors have access to capital at a lower cost than that available to us.

Seasonal Nature of Business

The price we receive for our natural gas production is impacted by seasonal fluctuations in demand for natural gas. The demand for natural gas typically peaks during the coldest months and tapers off during the milder months, with a slight increase during the summer to meet the demands of electric generators. The weather during any particular season can affect this cyclical demand for natural gas. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Hydraulic Fracturing

Hydraulic fracturing is used as a means to maximize the productivity of almost every well that we drill and complete, except in our offshore wells. Hydraulic fracturing is a necessary part of the completion process because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. Our proved developed non-producing and proved undeveloped reserves make up 19.4% of the total proved reserves, with approximately 30.7% of these requiring hydraulic fracturing as of December 31, 2024.

We believe we have followed and continue to substantially follow applicable industry standard practices and legal and regulatory requirements for groundwater protection in our hydraulic fracturing operations, which are subject to supervision by state and federal regulators (including the U.S. Bureau of Land Management (the “BLM”) on federal acreage). These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by regulatory agencies and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to essentially eliminate a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abnormal change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand, and the fluids are managed and used in accordance with applicable requirements.

Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it into approved disposal or injection wells. We currently do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, see “— Environmental, Occupational Health and Safety Matters and Regulations — Hydraulic Fracturing.”

Insurance

In accordance with customary industry practice, we maintain insurance against many, but not all, potential losses or liabilities arising from our operations and at costs that we believe to be economic. We regularly review our risks of loss and the cost and availability of insurance and revise our insurance accordingly. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses. We currently have insurance policies that include the following:

- Commercial General Liability;
- Primary Umbrella / Excess Liability;
- Property;
- Workers' Compensation;
- Employer's Liability;
- Maritime Employer's Liability;
- U.S. Longshore and Harbor Workers';
- Energy Package/Control of Well;
- Loss of Production Income;
- Cybersecurity;
- Oil Pollution Act Liability;
- Pollution Legal Liability;
- Charterer's Legal Liability;
- Non-Owned Aircraft Liability;
- Automobile Liability;
- Directors & Officers Liability;
- Employment Practices Liability;
- Crime; and
- Fiduciary Liability.

We continuously monitor regulatory changes and comments and consider their impact on the insurance market, along with and our overall risk profile. As necessary, we will adjust our risk and insurance program to provide protection at a level we consider appropriate while weighing the cost of insurance against the potential and magnitude of disruption to our operations and cash flows. Changes in laws and regulations could lead to changes in underwriting standards, limitations on scope and amount of coverage, and higher premiums, including possible increases in liability caps for claims of damages from oil spills.

Environmental, Occupational Health and Safety Matters and Regulations

General

Our oil and natural gas development and production operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, occupational health and safety aspects of our operations, or otherwise relating to protection of the environment and natural resources. These laws and regulations impose numerous obligations applicable to our operations, including the acquisition of certain permits before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; the suspension or revocation of necessary permits, licenses and authorizations; the requirement that additional pollution controls be installed; and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. We may also experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly owned or operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from our own actions that were in compliance with all applicable laws at the time such actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased in recent years. New laws and regulations continue to be enacted, particularly at the state level, and the long-term trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent new or more stringent 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.

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

Offshore Operations

Our oil and gas operations associated with our Beta properties are conducted on offshore leases in federal waters, and those operations are regulated by agencies such as BOEM and BSEE, which have broad authority to regulate our oil and gas operations associated with our Beta properties.

BOEM is responsible for managing environmentally and economically responsible development of the nation's offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, and National Environmental Policy Act ("NEPA") analysis and environmental review. Lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of offshore operations. BOEM generally requires that lessees have substantial net worth, post supplemental bonds or provide other acceptable assurances that the obligations will be met. In October 2020, BOEM and BSEE issued a proposed rule to clarify, streamline, and provide greater transparency to financial assurance requirements for the oil and gas industry, including streamlining the evaluation criteria for determining if and when additional security is required for Outer Continental Shelf ("OCS") leases, pipeline rights-of-way and rights-of-use and easement ("RUE") and revising the process for issuing decommissioning obligations for facilities on the OCS. Pursuant to prior Executive Order 13990, BOEM decided not to move forward with the BOEM-administered portions, and instead issued a new notice of proposed rulemaking to address the financial policy concerns. BSEE finalized the BSEE-related provisions, which became effective on May 18, 2023, to focus on clarifying decommissioning obligations of RUE grant holders and promulgate BSEE policy regarding the obligations of predecessors that must decommission their units. In April 2024, BOEM announced a final rule, which modified criteria for determining whether oil, gas, and sulfur lessees, RUE grant holders, and pipeline right-of-way grant holders are required to provide bonds or other financial assurance above what is currently required to ensure compliance with OCS obligations. The final rule also codified the use of the BSEE's probabilistic estimates of decommissioning costs in setting the levels of demand for supplemental financial assurance, removed restrictive provisions for third-party guarantees and decommissioning accounts, and added new criteria for cancelling supplemental financial assurance.

BSEE is responsible for safety and environmental oversight of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and training and environmental compliance programs. BSEE regulations require offshore production facilities and pipelines located on the OCS to meet stringent engineering and construction specifications, and in August 2023 and August 2024 BSEE announced two final rules which added safety-related regulations concerning the design and operating procedures of these facilities and pipelines, including regulations to safeguard against or respond to well blowouts and other catastrophes and manage equipment used in high pressure high temperature environments. BSEE regulations also restrict the flaring or venting of natural gas, prohibit the flaring of liquid hydrocarbons and govern the plugging and abandonment of wells located offshore and the installation and removal of all fixed drilling and production facilities.

BOEM and BSEE have adopted regulations providing for enforcement actions, including civil penalties and lease forfeiture or cancellation for failure to comply with regulatory requirements for offshore operations. If we fail to pay royalties or comply with safety and environmental regulations, BOEM and BSEE may require that our operations on the Beta properties be suspended or terminated, and we may be subject to civil or criminal liability, which may have a negative impact on our operations, capital expenditures, earnings or competitive position.

In addition to permits and approvals required by BOEM and BSEE, approvals and permits may be required from other agencies for the oil and gas operations associated with our Beta properties, such as the U.S. Coast Guard, the EPA, U.S. Department of Transportation, U. S. Army Corps of Engineers and the South Coast Air Quality Management District.

Hazardous Substances and Waste Handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also referred to 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 deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Also, comparable state statutes may not contain a similar exemption for petroleum, and it is also not uncommon for neighboring landowners and other third parties to file common law-based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Oil Pollution Act of 1990 ("OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of, and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a cleanup. We are also subject to analogous state statutes that impose liabilities with respect to oil spills. For example, the California Department of Fish and Wildlife's Office of Oil Spill Prevention and Response has adopted oil-spill prevention regulations that overlap with federal regulations.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is possible that these wastes, which could include wastes currently generated during our operations, could be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes." Any such changes, including to state programs, could result in an increase in our costs to manage and dispose of oil and gas waste, which could have a material adverse effect on our maintenance capital expenditures and operating expenses.

It is possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials ("NORM"). NORM are present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes into contact with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Administrative, civil and criminal penalties can be imposed for failure to comply with hazardous substance and waste handling requirements. We believe that we are in substantial compliance with the requirements of CERCLA, OPA, RCRA, and other applicable federal and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our hazardous substances and wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act"), the Safe Drinking Water Act ("SDWA"), the OPA and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and hazardous substances, into navigable waters of the United States, as well as 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. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). In June 2015, the EPA and the Corps issued a rule to revise the definition of "waters of the United States" ("WOTUS") for all Clean Water Act programs, which never took effect before being replaced by the Navigable Waters Protection Rule (the "NWPR") in April 2020. The NWPR was vacated by two separate federal district courts in late 2021. The definition of WOTUS was further impacted by the U.S. Supreme Court's decision issued in May 2023 in Sackett v. EPA wherein the Court held that the jurisdiction of the Clean Water Act extends only to those adjacent wetlands that are indistinguishable from traditional navigable bodies of water due to a continuous surface connection and rejected the "significant nexus" test embraced in earlier jurisprudence. In September 2023, the EPA and the Corps published a direct-to-final rule redefining WOTUS to align with the decision in Sackett. The final rule eliminated the "significant nexus" test from consideration when determining federal jurisdiction and clarified that the Clean Water Act only extends to relatively permanent bodies of water and wetlands that have a continuous surface connection with such bodies of water. However, roughly half of the states and other plaintiffs are continuing to challenge the rule, and the EPA and the Corps are using the pre-2015 definition of WOTUS in these states while litigation continues. As a result, substantial uncertainty exists with respect to future implementation of the September 2023 rule and the scope of CWA jurisdiction more generally.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of storm water or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits or specify other requirements for discharges or operations that may impact groundwater conditions. These same regulatory programs may also limit the total volume of water that can be discharged, hence limiting the rate of development and requiring us to incur compliance costs. Additionally, we are required to develop and implement spill prevention, control and countermeasure plans, in connection with on-site storage of significant quantities of oil.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Additionally, obtaining permits has the potential to delay the development of natural gas and oil projects. We maintain all required discharge permits necessary to conduct our operations and we believe we are in substantial compliance with their terms.

In addition, in some instances, the operation of underground injection wells for the disposal of wastewater has been alleged to cause earthquakes. For example, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. In some jurisdictions, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity or resulted in stricter regulatory requirements relating to the location and operation of underground injection wells. Such issues have also led to lawsuits by private parties alleging damages relating to induced seismicity. For example, the Railroad Commission of Texas (the "Commission") requires applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey, which are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The Commission is authorized to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Commission is also considering new restrictions that could limit the volume and pressure of produced water injected into disposal wells. Additionally, we conduct oil and gas drilling and production operations in the Mississippian Lime formation in Oklahoma, a high-water play, which requires us to dispose of large volumes of saltwater generated as part of our operations. The Oklahoma Geological Survey attributed an increase in seismic activity in Oklahoma to saltwater disposal wells in the Arbuckle formation and, the Oklahoma Corporation Commission (the "OCC"), whose Oil and Gas Conservation Division regulates oil and gas operations in Oklahoma, issued regulations targeting saltwater disposal activities in certain areas of interest within the Arbuckle formation. The regulations include operational requirements (i.e., mechanical integrity testing of wells permitted for disposal of 20,000 or more barrels of water per day, daily monitoring and recording of well pressure and discharge volume), as well as orders to shut-in wells, reduce well depths, or decrease disposal volumes. Under these regulations, the OCC ordered us to limit the volume of saltwater disposed of in saltwater disposal wells in the Arbuckle formation, and it established caps for ten of our saltwater disposal wells, which caps are still in place. To ensure that we had an adequate number of wells for disposal, we secured permits for additional saltwater disposal wells outside of the Arbuckle formation. We are currently in compliance with all OCC saltwater disposal requirements and have maintained our production base without any negative material impact. However, any future orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect or curtail our operations.

Hydraulic Fracturing

We use hydraulic fracturing extensively in our onshore operations, but not our offshore operations. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. Hydraulic fracturing involves using water, sand and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA's wastewater pretreatment standards prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to environmental requirements may result in increased costs.

The BLM had previously issued a rule that would restrict hydraulic fracturing on federal and Indian lands, but the BLM rescinded that rule in December 2017, overruling the objections of several environmental groups and states that challenged rescission of the rule. In July 2023, legislation was introduced in Congress that would have given the EPA the authority to regulate hydraulic fracturing processes across the U.S. and require U.S. fracturing companies to publicly disclose the chemicals used in such process, but that legislation did not pass out of committee.

Several states have also adopted, or are considering adopting, regulations requiring the disclosure of the chemicals used in hydraulic fracturing and/or otherwise imposing additional requirements for hydraulic fracturing activities. For example, Oklahoma requires oil and gas producers to report the chemicals they use in hydraulic fracturing to FracFocus.org, a national hydraulic fracturing chemical registry, or to the OCC, which will convey the information to FracFocus.org. The Louisiana Department of Natural Resources has adopted rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, Texas requires oil and natural gas operators to disclose to the Commission and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. Texas has also imposed requirements for drilling, putting pipe down and cementing wells, and testing and reporting requirements.

Certain governmental reviews have been conducted that focus on environmental aspects of hydraulic fracturing practices, which could lead to increased regulation. For example, in 2016, the EPA issued a report examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. The EPA has also issued a report on onshore conventional and unconventional oil and gas extraction wastewater management, and conducted a study of private wastewater treatment facilities, also known as centralized waste treatment facilities, accepting oil and gas extraction wastewater. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated various other aspects of hydraulic fracturing. These studies could spur initiatives to further regulate hydraulic fracturing and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Additionally, a number of lawsuits and enforcement actions have been initiated across the country, alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states (such as California) and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. We believe that we follow standard industry practices and legal requirements applicable to our hydraulic fracturing activities. Nonetheless, in the event of new or more stringent federal, state or local legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater or otherwise have negative impacts.

At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation 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.

Air Emissions

The federal Clean Air Act, as amended (“CAA”), and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. The South Coast Air Quality Management District (“SCAQMD”) is a regulatory subdivision of the State of California and is responsible for air pollution control from stationary sources within Orange County and designated portions of Los Angeles, Riverside, and San Bernardino Counties. Our Beta properties and associated facilities are subject to regulation by the SCAQMD. Federal, SCAQMD, and other state 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 EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits.

In November 2021, the EPA issued a proposed rule intended to establish standards for methane and volatile organic compounds, or VOCs, from new and modified oil and natural gas production and natural gas processing and transmission facilities. The proposed rule sought to make the existing regulations in Subpart OOOOa more stringent and create 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 (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). 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 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 removed an emissions monitoring exemption for small wellhead-only sites and created a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters". The EPA announced a final rule in December 2023, which, among other things, requires the phase out of routine flaring of natural gas from new oil wells and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance dates under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane from existing sources. The final emissions guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply.

Additionally, in 2016, the BLM finalized rules related to further controlling the venting and flaring of natural gas on BLM land, which was challenged by a group of states. In September 2018, the BLM published a final rule that revised the 2016 rules, which was again challenged by states and environmental groups. In April 2024, and later revised in November 2024, the BLM issued a final rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. 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 2023 EPA rule and the final 2024 BLM rule remain uncertain at this time.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Climate Change Regulation

At the international level, the United States joined the international community at the United Nations Framework Convention on Climate Change 21st Conference of the Parties ("COP21") in Paris, France in 2015, which resulted in an agreement intended to nationally determine their contributions and set GHG emission reduction goals every five years beginning in 2020. In February 2021, the prior Biden Administration announced reentry of the U.S. into the Paris Agreement along with a new "nationally determined contribution" for U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. Additionally, at the United Nations Framework Convention on Climate Change 28th Conference of the Parties ("COP28"), nearly 200 countries entered into an agreement that calls for actions towards achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, are to accelerate efforts towards the phase-down of unabated coal power, phase out inefficient fossil fuel subsidies, and take other measures that drive the transition away from fossil fuels in energy systems. Most recently, at the 29th Conference of the Parties ("COP29"), delegates approved rules to operationalize international carbon markets under Article 6 of the Paris Agreement, including a new Paris Agreement Crediting Mechanism to trade UN-approved carbon credits. Additionally, participants at COP29 representing 159 countries met to review progress toward the goals of the Global Methane Pledge and the addition of nearly $500 million in new grant funding for methane abatement. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and any similar commitment made under the UN Framework Convention on Climate Change. However, various state and local governments in the U.S. have publicly committed to furthering the goals of the Paris Agreement. It is not possible at this time to predict how legislation or regulations that may be adopted to address climate change, methane and other GHG emissions may impact our business.

In August 2022, the prior Biden Administration signed into law the Inflation Reduction Act. Among other things, the Inflation Reduction Act includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a "waste emissions charge" on certain oil and gas sources that are already required to report under 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. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. In November 2024, the EPA finalized a regulation to implement the Inflation Reduction Act's Waste Emissions Charge, which became effective on January 1, 2025. The fee imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 is $900 per ton emitted over annual methane emissions thresholds, and increases to $1,200 in 2025, and $1,500 in 2026. For the year ended December 31, 2024, the Company recognized $0.4 million in Waste Emission Charges.

At the state level, California enacted legislation in October 2023, further amended in 2024, that will ultimately require certain companies that do business in California and exceed specified financial thresholds to publicly disclose their Scopes 1, 2, and 3 GHG emissions, with third party assurance of such data, and issue public reports on climate-related financial risk and related mitigation measures. The implementing regulations for these laws are expected in 2025 and the requirements are currently set to begin taking effect on January 1, 2026, with additional requirements phasing in through 2030. The legislation on GHG emission disclosures in California is currently subject to legal challenge in federal court. While we are still assessing the impact of these requirements, additional reporting obligations could cause us to incur increased costs.

Additionally, on March 6, 2024, the SEC adopted new rules regarding the enhancement and standardization of climate-related disclosures for investors (the "SEC Climate Rules"). The SEC Climate Rules require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to, information about material climate-related risks; the registrant's governance of climate-related risks and relevant risk management processes; material climate-related targets and goals; and certain financial effects resulting from severe weather events and other natural conditions in a note to their audited financial statements (subject to de minimis thresholds). Larger registrants will also be required to disclose information about material Scope 1 and 2 greenhouse gas emissions, which will be subject to a phased-in assurance requirement. However, the SEC voluntarily stayed the SEC Climate Rules in April 2024 pending judicial review of petitions challenging the rules. We are currently evaluating the impact of the SEC Climate Rules and there remains uncertainty as to whether these rules will withstand pending and future legal challenges.

While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not currently adversely impacted by existing federal, state and local climate change initiatives. The adoption and implementation of any new regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, any GHG regulation could increase our costs of compliance by requiring enhanced disclosure obligations, potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric driven compression at facilities to obtain regulatory permits and approvals in a timely manner. Such climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Moreover, any legislation or regulatory programs to reduce GHG emissions could increase the cost of consumption, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce. However, the Supreme Court's decision in Loper Bright Enterprises v. Raimondo to overrule Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc. ends 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, and 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 federal climate change rules remain uncertain at this time.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to NEPA. NEPA requires federal agencies, including the U.S. Departments of the Interior and Agriculture, to evaluate major federal actions having the potential to significantly impact the human environment. In the course of such evaluations, an agency evaluates the potential direct, indirect and cumulative impacts of a proposed project. If the proposed impacts are considered significant, the agency will prepare a detailed environmental impact statement that is made available for public review and comment. In July 2020, the White House's Council on Environmental Quality ("CEQ") published a final rule to amend the NEPA implementing regulations intended to streamline the environmental review process, including shortening the time for review as well as eliminating the requirement to evaluate cumulative impacts. The final rule required federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date (which was extended to two years in June 2021). In October 2021, the 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 proposed 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, environmental justice and climate change objectives. 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 CEQ's NEPA regulations. 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. The potential impact of further changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our operations.

Endangered Species Act and Migratory Bird Treaty Act

The federal ESA was established to protect endangered and threatened species and their habitat. If a species is listed as threatened or endangered pursuant to the ESA, restrictions may be imposed on activities adversely affecting that species or its habitat. The U.S. Fish and Wildlife Service ("FWS") must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. In January 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. However, the Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental taking under certain prescribed conditions. The future of this rulemaking is uncertain. In April 2024, the U.S. FWS issued three final rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. However, in January 2025, President Trump issued an executive order declaring a national energy emergency and directing agency heads to identify actions to facilitate the energy supply that may be subject to emergency treatment, including under the ESA. Consequently, future implementation and enforcement of these rules remain uncertain at this time. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and consequently, adversely affect our results of operations and financial position. 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.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government 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. We believe that our operations are in substantial compliance with the OSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on our assets. Additionally, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress, and the development of regulations continues in the U.S. Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the 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;
- transportation of materials and equipment to and from our well sites and facilities;
- transportation and disposal of produced fluids and natural gas; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Sale and Transportation of Gas and Oil

The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the construction and operations of interstate gas pipeline facilities and the rates, terms and conditions of service under which companies provide interstate transportation of gas, oil and other liquids by pipeline. Although the FERC does not have jurisdiction over the production of gas, the FERC exercises regulatory authority over wholesale sales of gas in interstate commerce through the issuance of blanket marketing certificates that authorize the wholesale sale of gas at market rates and the imposition of a code of conduct on blanket marketing certificate holders that regulate certain affiliate interactions. The FERC does not regulate the sale of oil or petroleum products or the construction of oil or other liquids pipelines, but does regulate the rates and terms and conditions of service on oil and liquids pipelines. The FERC also has oversight of the performance of wholesale natural gas markets, including the authority to facilitate price transparency and to prevent market manipulation. In furtherance of this authority, the FERC imposed an annual reporting requirement on all industry participants, including otherwise non-jurisdictional entities, engaged in wholesale physical natural gas sales and purchases in excess of a minimum level. These agency actions have been intended to foster increased competition within all phases of the gas industry. To date, the FERC's pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the gas industry will have on our gas sales efforts.

The FERC and other federal agencies, the U.S. Congress or state legislative bodies and regulatory agencies may consider additional proposals or proceedings that might affect the gas or oil industries. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any such proposal will affect us any differently than it would affect other gas or oil producers with which we compete.

The Beta properties include the San Pedro Bay Pipeline Company, which owns and operates an offshore crude oil pipeline. This pipeline is subject to regulation by the FERC under the Interstate Commerce Act and the Energy Policy Act of 1992. Tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, must be just and reasonable and not unduly discriminatory. FERC regulations require that interstate oil pipeline transportation rates and terms of service be filed with the FERC and posted publicly. The FERC has established a formulaic methodology for oil and liquids pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. During the last review period, FERC set the index level in December 2020. Both pipelines and pipeline customers sought rehearing of the index level, and in January 2022, FERC issued a rehearing order setting a lower index price, effective July 1, 2021, of the producer price index for finished goods minus 0.21%. Pipelines challenged this decision and on July 26, 2024, the D.C. Circuit vacated the rehearing order. Subsequently, on September 17, 2024, FERC issued an order reinstating the index price of producer price index for finished goods plus 0.78%. Then, on October 17, 2024, FERC issued a supplemental notice of proposed rulemaking proposing to reduce the index price back to the producer price index for finished goods minus 0.21%; that proposal is now pending at FERC. The San Pedro Bay Pipeline Company uses the indexing methodology to change its rates.

The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. BOEM/BSEE has established formal and informal complaint procedures for shippers that believe they have been denied open and non-discriminatory access to transportation on the OCS.

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates the safety of all pipeline transportation in or affecting interstate or foreign commerce, including pipeline facilities on the OCS. The San Pedro Bay pipeline is subject to regulation by the PHMSA. In recent years, PHMSA has been active in proposing and finalizing additional regulations for natural gas and hazardous liquids pipelines. For example, in January 2017, PHMSA finalized new regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, repairs and leak detection), regardless of the pipeline's proximity to a high consequence area ("HCA"). The final rule also requires all pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual and accident reporting requirements to gravity lines, and all gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes, or other similar events that are likely to damage infrastructure. In addition, in April 2016, PHMSA proposed a rule regarding the safety of natural gas transmission pipelines and gas gathering pipelines. In October 2019, PHMSA issued a final rule on the natural gas transmission lines portion of the April 2016 rulemaking, and in November 2021 PHMSA issued a final rule on the gathering lines portion of the April 2016 rulemaking. Under the new final rule, operators of onshore natural gas gathering pipelines that were previously excluded from certain PHMSA regulations face additional testing, safety and reporting requirements or may be forced to reduce their allowable operating pressures, which would reduce the amount of capacity available to the Company. Certain reporting requirements arising from the new PHMSA rule took effect in 2022, with additional requirements taking effect later in 2023.

Moreover, effective April 2017, the PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations. PHMSA updates the maximum administrative civil penalties each year to account for inflation, and as of December 2024, the penalty limits are up to $272,926 per violation per day and up to $2,729,245 for a related series of violations. The PHMSA has also issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. In March 2022, PHMSA announced a final rule, effective October 5, 2022, to improve pipeline safety and reduce methane emissions by requiring the installation of remotely controlled or automatic shut-off valves, or similar technologies, in new and replaced onshore natural gas and other hazardous liquid pipelines. In August 2022, PHMSA passed a final rule, effective May 24, 2023, to protect the safety and environmental protection of onshore gas transmission pipelines, which establishes new standards for identifying threats, failures and worst-case scenarios throughout from initial failure through conclusion of an incident. Additionally, on January 17, 2025, PHMSA issued a final rule to implement congressional mandates to reduce methane leaks from new and existing natural gas transmission, distribution and gathering pipelines and liquefied natural gas facilities. The final rule will be effective 180 days after the date of publication in the Federal Register.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

Anti-Market Manipulation Laws and Regulations

The FERC, with respect to the purchase or sale of natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction and the Federal Trade Commission (the “FTC”) with respect to petroleum and petroleum products, operating under various statutes, have each adopted anti-market manipulation regulations, which prohibit, among other things, fraud and price manipulation in the respective markets. These agencies hold substantial enforcement authority, including the ability to assess substantial civil penalties, to order repayment or disgorgement of profits and to recommend criminal penalties. 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.

Derivatives Regulation

Comprehensive financial reform legislation was signed into law by former President Obama on July 21, 2010 (the “Dodd-Frank Act”). This legislation called for the Commodities Futures Trading Commission (the “CFTC”) to regulate certain markets for derivative products, including over-the-counter derivatives. The CFTC has issued several new relevant regulations and rulemakings to implement the Dodd-Frank Act, the mandate to cause significant portions of derivatives markets to clear through clearinghouses, along with other mandated changes. While some of these rules have been finalized, some have not. As a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The CFTC’s final rules were challenged in court by two industry associations and were vacated and remanded by a federal district court. Subsequently, the CFTC proposed new rules in November 2013 and December 2016. In January 2020, the CFTC withdrew the 2013 and 2016 proposals. In January 2021 the CFTC issued a final rule on the matter, effective March 15, 2021. The final rule includes limits on positions in (1) certain “Core Referenced Futures Contracts,” including contracts for several energy commodities; (2) futures and options on futures that are directly or indirectly linked to the price of a Core Referenced Futures Contract, or to the same commodity for delivery at the same location as specified in that Core Referenced Futures Contract; and (3) economically equivalent swaps. The final rule also includes exemptions from position limits for bona fide hedging activities.

The Dodd-Frank Act and new, related regulations may prompt counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation 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, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may become less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations. Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our sales of oil and natural gas are also subject to anti-manipulation and anti-disruptive practices authority under (i) the Commodity Exchange Act (the "CEA"), as amended by the Dodd-Frank Act, and regulations promulgated thereunder by the CFTC, and (ii) the Energy Independence and Security Act of 2007 (the "EISA") and regulations promulgated thereunder by the FTC. The CEA, as amended by the Dodd-Frank Act, prohibits any person from using or employing any manipulative or deceptive device in connection with any swap, or a contract for sale of any commodity, or for future delivery on such commodity, in contravention of the CFTC's rules and regulations. It also prohibits knowingly delivering or causing to be delivered false, misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity. The FTC's Petroleum Market Manipulation Rule, issued pursuant to EISA, prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. Under both the CEA and the EISA, fines for violations can be up to $1,000,000 per day per violation (subject to adjustment for inflation) and certain knowing or willful violations may also lead to a felony conviction.

Additional proposals and proceedings that may affect the crude oil and natural gas industry are pending before the U.S. Congress, federal agencies and the courts. The Company cannot predict the ultimate impact these proposals may have on its crude oil and natural gas operations, but the Company does not expect any such action to affect the Company differently than it will affect other gas or oil producers with which we compete.

State Regulation

Various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, the baseline Texas severance tax on oil and gas is 4.6% of the market value of oil produced and 7.5% of the market value of gas produced and saved. A number of exemptions from or reductions of the severance tax on oil and gas production are provided by the State of Texas which effectively lowers the cost of production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Human Capital

Overview

On December 31, 2024, the Company had 229 employees, none of whom were represented by labor unions or covered by any collective bargaining agreement. We strive to create a high-performing culture and positive work environment that allows us to attract and retain a diverse group of talented individuals who can foster the Company's success. To attract and retain top talent, our human resources programs are designed to reward and incentivize our employees through competitive compensation practices, our commitment to employee health and safety, training and talent development and our commitment to diversity and inclusion.

Safety

Safety is our highest priority, and we are dedicated to the well-being of our employees, contractors, business partners, stakeholders and the environment. We promote safety with a robust health and safety program, which includes employee orientation and training, contractor management, risk assessment, hazard identification and mitigation, audits, incident reporting and investigation, and corrective and preventative action development.

In addition, we employ environmental, health and safety personnel at each of our asset locations, who provide in-person safety training and regular safety meetings. We also utilize learning management software to provide safety training on a variety of topics, and we contract with third-party technical experts to facilitate training on specialized topics that are unique to each of our areas of operation.

It is our policy to provide our employees with a safe and healthy workplace and to follow procedures aimed at safeguarding employees. We believe accident prevention and efficiency in production run hand-in-hand. Our internal Stop Work Authority empowers employees to pause operations so that an observed potential hazard can be eliminated or mitigated.

We are committed to maintaining a safe and healthy work environment by complying with state and federal regulations concerning the health and safety of our employees. Our employees are expected to demonstrate a cooperative spirit by working together to help us in this effort. As such, every employee is directly responsible for the proper care and use of Amplify property and equipment placed in their charge, either temporarily or on a regular basis.

Compensation

We operate in a highly competitive environment and have designed our compensation program to attract, retain and motivate talented and experienced individuals. Our compensation philosophy is designed to align the interests of our workforce with those of our stakeholders and to reward them for achieving the Company’s business and strategic objectives and driving shareholder value. We consider competitive market compensation paid by our peers and other companies comparable to us in size, geographic location and operations in order to ensure our compensation remains competitive and fulfills our goal of recruiting and retaining talented employees.

Training and Development

We are committed to the training and development of our employees. Employees are regularly provided training opportunities to develop skills in leadership, safety, and technical acumen, which bolsters our efforts in conducting business in a safe manner and with high ethical standards. Further, we believe that supporting our employees in achieving their career and development goals is a key element of our approach to attracting and retaining top talent. We encourage our employees to advance their knowledge and skills and to network with other professionals in order to pursue career advancement and potential future opportunities with the Company. Our employees are able to attend training seminars and off-site workshops or to join professional associations that will enable them to remain up to date on the latest changes and best practices in their respective fields.

Diversity and Inclusion

We are committed to supporting a diverse and inclusive workplace and career development opportunities to attract and retain talented employees. As of December 31, 2024, approximately 15% of our total workforce self-identified as a racial or ethnic minority and approximately 16% self-identified as female. As of the same date, approximately 32% of the employees located in our corporate headquarters self-identified as a racial or ethnic minority and approximately 48% self-identified as female. We believe that a diverse workforce provides the opportunity to obtain unique perspectives, experiences, ideas, and solutions to help our business succeed. It is our policy to prohibit discrimination and harassment of any type and afford equal employment opportunities to employees and applicants without regard to race, color, religion, sex, national origin, age, disability, genetic information, veteran status, or any other basis protected by federal, state or local law. Further, it is our policy to forbid retaliation against any individual who reports, claims, or makes a charge of discrimination or harassment, fraud, unethical conduct, or a violation of our Company policies. To sustain and promote an inclusive culture, we maintain a robust compliance program rooted in our Code of Business Conduct and Ethics and other Company policies, which provide policies and guidance on non-discrimination, anti-harassment, and equal employment opportunities. We require all employees to complete periodic training sessions on various aspects of our corporate policies through an annual acknowledgment and certification process.

Health and Wellness

We support our employees and their families by offering a robust package of health and welfare benefits, medical, dental, and vision insurance plans for employees and their families, life insurance and long-term disability plans, paid time off for holidays, vacation, sick leave, and other personal leave, and health and dependent care savings accounts. We also provide our employees with a 401(k) plan that includes a competitive company match, and employees have access to a variety of resources and services to help them plan for retirement.

In addition to these programs, we have several other programs designed to further promote the health and wellness of our employees, including, among others, an employee assistance program that offers counseling and referral services for a broad range of personal and family situations.

The success of our business is fundamentally connected to the safety and well-being of our employees. Our focus remains on providing a safe office environment for our employees while continuing to allow for remote work, hybrid work and flexible work schedules where feasible. With the support of the varying work arrangements and a geographically dispersed workforce, we continue to develop ways to best support our people.

Offices

Our principal executive office is located at 500 Dallas Street, Suite 1700, Houston, Texas 77002. Our main telephone number is (832) 219-9001.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our website at www.amplifyenergy.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. Our website also includes our Code of Business Conduct and Ethics, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating & governance committee. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

The SEC maintains a website that contains reports, proxy and information statements, and other information regarding the Company at www.sec.gov.

ITEM 1A. RISK FACTORS

Our business and operations are subject to many risks. The risks described below, in addition to the risks described in "Item 1. Business" of this Annual Report, may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. You should carefully consider the following risk factors together with all of the other information included in this Annual Report, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this Annual Report could have a material adverse effect on our business, financial position, results of operations and cash flows and the trading price of our securities could decline, and you could lose all or part of your investment.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and greatly affect our business, results of operations and financial condition. Any decline in, or sustained low levels of, oil, natural gas and NGL prices will cause a decline in our cash flow from operations, which could materially and adversely affect our business, results of operations and financial condition.

Our revenues, operating results, profitability, liquidity, future growth and the value of our assets depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;

- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the cost of exploring for developing, producing and transporting reserves;
- the price and quantity of foreign imports, including volatility as a result of tariffs and other trade-related disputes;
- political and economic conditions in oil producing countries, including conflicts in or among the Middle East, Africa, South America, Russia and Israel;
- the ability of members of the Organization of Petroleum Exporting Countries ("OPEC") to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with a pandemic, epidemic or outbreak of an infectious disease;
- risks associated with operating drilling rigs;
- technological advances affecting exploration and production operations and overall energy consumption;
- domestic and foreign governmental regulations and taxes;
- the impact of energy conservation efforts;
- the continued threat of terrorism and the impact of military and other action, including the Russian invasion of Ukraine and ongoing conflicts in the Middle East, and the potential destabilizing effect such conflicts may pose for those regions and/or the global oil and natural gas markets;
- the price and availability of competitors' supplies of oil and natural gas and alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2024, the NYMEX-WTI oil future price ranged from a high of $122.11 per Bbl to a low of $(37.63) per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $9.68 per MMBtu to a low of $1.48 per MMBtu. For the year ended December 31, 2024, the WTI posted prices ranged from a high of $86.91 per Bbl on April 5, 2024 to a low of $65.75 per Bbl on September 10, 2024 and NYMEX-Henry Hub natural gas market price ranged from a high of $3.95 per MMBtu on December 24, 2024 to a low of $1.58 per MMBtu on February 15, 2024. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which has different uses and different pricing characteristics, have sustained depressed realized prices during this period and are generally correlated with the price of oil. A further or extended decline in commodity prices could materially and adversely affect our business, results of operations and financial condition.

If commodity prices decline for a prolonged period, a significant portion of our development projects may become uneconomic and result in write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and our ability to fund our operations.

Oil, natural gas and NGL prices have experienced significant volatility over the past few years. An extended decline in commodity prices could render many of our development and production projects uneconomical and result in a downward adjustment of our reserve estimates, which would reduce our borrowing base and our ability to fund our operations.

No impairment expense was recognized for the years ended December 31, 2024 and 2023. An extended decline in commodity prices may cause us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We may in the future incur impairment charges that could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our Revolving Credit Facility.

Our business could be adversely affected by a decline in general economic conditions or a weakening of the broader energy industry, and inflation may adversely affect our financial position and operating results.

A prolonged economic slowdown or recession, adverse events relating to the energy industry, volatility due to tariffs or other trade-related disputes, or regional, national, or global economic conditions and factors, particularly a slowdown in the exploration and production industry, could negatively impact our operations and therefore adversely affect our results. The risks associated with our business are more acute during periods of economic slowdown or recession because such periods may be accompanied by decreased demand for oil and natural gas and decreased prices for oil and natural gas.

Inflationary factors, such as increases in the labor costs, material costs, and overhead costs, may also adversely affect our financial position and operating results. Inflation has also resulted in higher interest rates in the United States, which could increase our cost of debt borrowing in the future.

Loss of our key executive officers or other key personnel, or an inability to attract and retain such officers and personnel, could negatively affect our business.

Our future success depends on the skills, experience and efforts of our key executive officers. The sudden loss of any of these executives' services or our failure to appropriately plan for any expected key executive succession could materially and adversely affect our business and prospects, as we may not be able to find suitable individuals to replace them on a timely basis, if at all. Additionally, we also depend on our ability to attract and retain qualified personnel to operate and expand our business. If we fail to attract or retain talented new employees, our business and results of operations could be negatively affected.

We may be unable to maintain compliance with the covenants in the Revolving Credit Facility, which could result in an event of default thereunder that, if not cured or waived, would have a material adverse effect on our business and financial condition.

Under our Revolving Credit Facility, we are required to (i) maintain, as of the date of determination, a maximum total debt to EBITDAX ratio of 3.00 to 1.00, (ii) maintain a current ratio of not less than 1.00 to 1.00, and (iii) hedge at least 50% − 75% of our estimated production from total proved developed producing reserves. If we were to violate any of the covenants under our Revolving Credit Facility and were unable to obtain a waiver or amendment, it would be considered a default after the expiration of any applicable grace period. If we were in default under our Revolving Credit Facility, then the lenders may exercise certain remedies including, among others, declaring all borrowings outstanding thereunder, if any, immediately due and payable. This could adversely affect our operations and our ability to satisfy our obligations as they come due, because we might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our Revolving Credit Facility are secured by mortgages on not less than 90% of the PV-9 value of our oil and gas properties together with all or substantially all material midstream assets necessary to operate our proved, developed and producing oil and gas properties, and if we are unable to repay our indebtedness under our Revolving Credit Facility, the lenders could seek to foreclose on our assets.

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

Restrictive covenants in our Revolving Credit Facility impose significant operating and financial restrictions on us and our subsidiaries. These restrictions limit our ability to, among other things:

- incur additional liens;
- incur additional indebtedness;
- merge, consolidate or sell our assets;
- pay dividends or make other distributions or repurchase or redeem our stock;
- make certain investments; and
- enter into transactions with our affiliates.

Our Revolving Credit Facility also requires us to comply with certain financial maintenance covenants as discussed above. A breach of any of these covenants could result in a default under our Revolving Credit Facility. If a default occurs and remains uncured or unwaived, the administrative agent or majority lenders under our Revolving Credit Facility may elect to declare all borrowings outstanding thereunder, if any, together with accrued interest and other fees, to be immediately due and payable. The administrative agent or majority lenders under our Revolving Credit Facility would also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay our indebtedness when due or declared due, the administrative agent will also have the right to proceed against the collateral pledged to it to secure the indebtedness under our Revolving Credit Facility. If such indebtedness were to be accelerated, our assets may not be sufficient to repay in full our secured indebtedness.

We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants in our Revolving Credit Facility. The terms and conditions of our Revolving Credit Facility affect us in several ways, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increasing our vulnerability to economic downturns and adverse developments in our business;
- limiting our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- placing restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- limiting management’s discretion in operating our business.

Our lenders periodically redetermine the amount we may borrow under our Revolving Credit Facility, which may materially impact our operations.

Our Revolving Credit Facility allows us to borrow in an amount up to the borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. The borrowing base is subject to redetermination on at least a semi-annual basis primarily based on an engineering report with respect to our estimated natural gas, oil and NGL reserves, which takes into account the prevailing natural gas, oil and NGL prices at such time, as adjusted for the impact of our commodity derivative contracts. Accordingly, declining commodity prices may have an impact on the amount we can borrow, which could affect our cash flows and ability to execute our business plans. Any material reduction in the borrowing base would materially and adversely affect our business and financing activities, limit our flexibility and management's discretion in operating our business, and increase the risk that we may default on our debt obligations. In addition, as hedges roll off, the borrowing base is subject to further reduction. Our Revolving Credit Facility requires us to repay any deficiency over a certain period or pledge additional oil and gas properties to eliminate such deficiency within 30 days of notice. If our outstanding borrowings exceed the borrowing base and we are unable to repay the deficiency or pledge additional oil and gas properties to eliminate such deficiency, our failure to repay any of the installments due related to the borrowing base deficiency would constitute an event of default under the Revolving Credit Facility and as such, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, or foreclose against the assets securing the obligations owed under our Revolving Credit Facility.

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

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

Our hedging strategy may not effectively mitigate the impact of commodity price volatility from our cash flows, and our hedging activities could result in cash losses and may limit potential gains.

We intend to maintain a portfolio of commodity derivative contracts covering at least 50%- 75% of our estimated production from proved developed producing reserves over a one-to-three-year period at any given point in time. These commodity derivative contracts include natural gas, oil and NGL financial swaps, put options, costless collars, and three-way collars. The prices and quantities at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices and price expectations, at the time we enter into these transactions, which may be substantially higher or lower than current or future oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices received for our future production. Many of the derivative contracts to which we will be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil, natural gas and NGL prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could significantly reduce our cash flow and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as NYMEX or ICE, that are used for calculating hedge positions. The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. For example, our California oil typically has a lower gravity, and a portion has higher sulfur content, than oil sold at certain benchmark prices. Therefore, because our oil requires more complex refining equipment to convert it into high value products, it may sell at a discount to those prices. These discounts, if significant, could reduce our cash flows and adversely affect our results of operations and financial condition.

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

It is not possible to measure underground accumulations of oil or natural gas in an exact way. The process of estimating natural gas and oil 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 our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of operating and 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 natural gas and oil prices, drilling and operating expenses, capital expenditures and availability of funds.

Actual future production, oil prices, natural gas prices, revenues, development expenditures, operating expenses and quantities of recoverable reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

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

The present value of future net cash flows from our proved reserves shown in this report, or standardized measure, may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the FASB, we base the estimated discounted future net cash flows from our proved reserves on the trailing 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on 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 the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements, which is required by the SEC and FASB, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

The failure to replace our proved oil and natural gas reserves could adversely affect our business, financial condition, results of operations, production and cash flows.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production and therefore, our cash flows, are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production at economically acceptable terms, which would materially and adversely affect our business, financial condition and results of operations.

If we reduce our capital spending in an effort to conserve cash, this would likely result in production being lower than anticipated, and could result in reduced revenues, cash flows from operations and income. Further, if the borrowing base under our Revolving Credit Facility decreases, or our revenues decrease, as a result of lower oil or natural gas prices or for any other reason, we may not be able to obtain the capital necessary to sustain our operations.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that may result in a total loss of investment or otherwise adversely affect our business, financial condition, results of operations and cash flows.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then-realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of our development and production activities are subject to numerous uncertainties beyond our control and increases in those costs can adversely affect the economics of a project. Further, our development and production operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor, electrical power or other services;
- unusual or unexpected geological formations;
- composition of sour natural gas, including sulfur, carbon dioxide and other diluent content;
- unexpected operational events and conditions;
- failure of down hole equipment and tubulars;
- loss of wellbore mechanical integrity;
- failure, unavailability or shortage of capacity of gathering and transportation pipelines, or other transportation facilities;
- human errors, facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour natural gas;
- title problems;
- loss of drilling fluid circulation;
- hydrocarbon or oilfield chemical spills;
- fires, blowouts, surface craterings and explosions;
- surface spills or underground migration due to uncontrollable flows of oil, natural gas, formation water or well fluids;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements; and
- adverse weather conditions and natural disasters.

Additionally, our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including natural disasters, the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, all of which could cause substantial financial losses. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The location of any properties and other assets near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of potential damages resulting from these risks.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations are delayed or canceled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and results of operations may be adversely affected. If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our business, financial condition, results of operations and cash flows.

Expenses not covered by our insurance could have a material adverse effect on our financial position and results of operations.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, insurance against all operational risk is not available to us. These insurance policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. Pollution and environmental risks generally are not fully insurable. In addition, we cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. A liability, claim or other loss not fully covered by insurance could have a material adverse effect on our business, financial position, results of operations and cash flows.

The production from our Bairoil properties could be adversely affected by the cessation or interruption of the supply of CO_2 to those properties.

We inject water and CO_2 into formations on substantially all of the Bairoil properties to increase production of oil and natural gas. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If we are unable to produce oil and gas by injecting CO_2 in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 to enhance production is subject to our ability to obtain sufficient quantities of CO_2. If, under our CO_2 supply contracts, the supplier is unable to deliver its contractually required quantities of CO_2 to us, or if our ability to access adequate supplies is impeded, then we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes will be negatively impacted.

Many of our properties are in areas that may have been partially depleted or drained by offset wells.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests lying contiguous or adjacent to or adjoining any of our properties could take actions, such as drilling additional wells that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further exploit and develop our reserves.

Our expectations for future development activities are planned to be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

We have identified drilling, recompletion and development locations and prospects for future drilling, recompletion and development. These drilling, recompletion and development locations represent a significant part of our future drilling and enhanced recovery opportunity plans. We cannot predict in advance of drilling, testing and analysis of data whether any particular drilling location will yield production in sufficient quantities to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. Our ability to drill, recomplete and develop locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure and lease expirations. Because of these uncertainties, we cannot be certain of the timing of these activities or that they will ultimately result in the realization of estimated proved reserves or meet our expectations for success. As such, our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our estimated reserves, financial condition, results of operations and cash flows.

Part of our strategy may involve using horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations may involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we may face while drilling horizontal wells include, but are not limited to, the following:

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

Risks that we may face while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the target reservoir formation as planned, including the planned number of stages;
- the ability to run tools 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.

If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

Our potential use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies and we could incur losses as a result of such expenditures. As a result, future drilling activities may not be successful or economical, which could have a material adverse impact on our financial condition, results of operations and cash flows.

SEC rules could limit our ability to book additional PUDs in the future.

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 will likely continue to limit our ability to book additional PUDs, especially in a time of depressed commodity prices. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year timeframe.

The unavailability or high cost of rigs, equipment, supplies and crews could delay our operations, increase our costs and delay forecasted revenue.

Our industry is cyclical, and historically there have been periodic shortages of rigs, equipment, supplies and crew. Sustained declines in oil and natural gas prices may reduce the number of service providers for such rigs, equipment, supplies and crews, contributing to or resulting in shortages. Alternatively, during periods of higher oil and natural gas prices, the demand for rigs, equipment, supplies and crews is increased and can lead to shortages of, and increasing costs for, development equipment, supplies, services and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict the Company's ability to drill the wells and conduct the operations that it currently has planned relating to the fields where our properties are located. In addition, some of our operations require supply materials for production, such as CO_2, which could become subject to shortages and increased costs. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and impact our development plan, which would thus affect our financial conduction, results of operations and our cash flows.

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

The existence of a material title deficiency can render a lease worthless and can 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.

Development and production of oil and natural gas in offshore waters have inherent and historically higher risk than similar activities onshore.

Our offshore operations are subject to a variety of operating risks specific to the marine environment, such as a dependence on a limited number of electrical transmission lines, as well as capsizing, collisions and damage or loss from adverse weather conditions. Offshore activities are subject to more extensive governmental regulation than our other oil and natural gas activities. We are vulnerable to the risks associated with operating offshore Southern California, including risks relating to:

- impacts of climate change and natural disasters such as earthquakes, tidal waves, mudslides, fires and floods;
- oil field service costs and availability;
- compliance with environmental and other laws and regulations;
- third-party marine vessels, including situations similar to the Incident;
- remediation and other costs resulting from oil spills, releases of hazardous materials and other environmental and natural resource damages; and
- failure of equipment or facilities.

In addition to lost production and increased costs, these hazards could cause serious injuries, fatalities, contamination or property damage for which we could be held responsible. The potential consequences of these hazards are particularly severe for us because significant portions of our offshore operations are conducted in environmentally sensitive areas, including areas with significant residential populations and public and commercial infrastructure. An accidental oil spill or release on or related to offshore properties and operations could expose us to joint and several strict liability, without regard to fault, under applicable law for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of remediating a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. If an oil discharge or substantial threat of discharge were to occur, we may be subject to regulatory scrutiny and liable for costs and damages, which costs and damages could be material to our business, financial condition or results of operations and could subject us to criminal and civil penalties. Finally, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed.

Adverse developments in our operating areas could adversely affect our business, financial condition, results of operations and cash flows.

Our properties are located in the Rockies, federal waters offshore Southern California, East Texas / North Louisiana, Oklahoma and Eagle Ford. An adverse development in the oil and natural gas business of any of these geographic areas, such as in our ability to attract and retain field personnel or in our ability to comply with local regulations, could adversely affect our business, financial condition, results of operations and cash flows.

We are dependent upon a small number of significant customers for a substantial portion of our production sales. The loss of those customers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition and results of operations.

We had three customers that each accounted for 10% or more of total reported revenues for the year ended December 31, 2024. The loss of these customers or any significant customer, should we be unable to replace them, could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. Also, if any significant customer reduces the volume it purchases from us, we could experience a temporary interruption in sales of, or may receive a lower price for, our production, and our revenues and cash flows could decline. For instance, in October 2024, Phillips 66 announced its plan to cease operations at its Los Angeles area refinery in the fourth quarter of 2025. While we are actively engaging in discussions with Phillips 66 to understand the full scope of the impact on our business, this refinery has historically represented a significant portion of our sales to Phillips 66. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production. See “Item 1. Business — Operations — Marketing and Major Customers.”

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our oil and natural gas receivables. The inability or failure of our significant customers, or any purchasers of our production, to meet their payment obligations to us or their insolvency or liquidation could have a material adverse effect on our results of operations. To the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge to earnings of that period for the probable loss and could suffer a material reduction in our liquidity and cash flows.

We are exposed to trade credit risk in the event of nonperformance by our vendors and other counterparties in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors and other counterparties. Some of our vendors and other counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors and other counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors’ and other counterparties’ liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors and/or counterparties could adversely affect our business, financial condition, results of operations and cash flows.

We may be unable to compete effectively with larger companies.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry-on refining operations and market petroleum and other products on a regional, national or worldwide basis and many of our competitors have access to capital at a lower cost than that available to us. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition, results of operations and cash flows.

Our business depends in part on pipelines, gathering systems and processing facilities owned by us or others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, gathering systems and processing facilities owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. For example, our ability to produce and sell oil from the Beta properties will depend on the availability of the pipeline infrastructure between platforms as well as the San Pedro Bay Pipeline for delivery of that oil to shore, and any unavailability of that pipeline infrastructure or pipeline could cause us to shut in all or a portion of the production from the Beta properties for the length of such unavailability. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided with only limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business, financial condition, results of operations and cash flows.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations administered by governmental authorities vested with broad authority relating to the exploration for and the development, production and transportation of oil and natural gas. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our oil and natural gas development and production operations are also subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. We may also experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. Thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly owned or operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased in recent years. New laws and regulations continue to be enacted, particularly at the state level, and, under the Biden Administration, the long-term trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. 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.

Further, the Mineral Leasing Act of 1920, as amended (the "Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign entity except through equity ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or entities of the United States. If these restrictions are violated, the oil and natural gas lease can be canceled in a proceeding instituted by the United States Attorney General. We qualify as an entity formed under the laws of the United States or of any U.S. state or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. It is possible that our stockholders may be citizens of foreign countries who do not own their stock in a U.S. corporation, or that even if such stock are held through a U.S. corporation, their country of citizenship may be determined to be non-reciprocal countries under the Mineral Act. In such event, any federal onshore oil and natural gas leases held by us could be subject to cancellation based on such determination.

See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations" and "— Other Regulation of the Oil and Natural Gas Industry" for a description of the more significant laws and regulations that affect us.

Our business is subject to climate-related transition risks, including fuel conservation measures, technological advances and increasing public attention to climate change and environmental matters, which could reduce demand for oil and natural gas and have an adverse effect on our business, financial condition and reputation.

Increased attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on responding to climate change, together with fuel conservation measures, alternative fuel requirements, incentives to conserve energy or use alternative energy sources, 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, increasing consumer demand for alternatives to oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles), societal expectations on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, and technological advances in fuel economy and energy transmission, storage, consumption and generation devices (including advances in wind, solar and hydrogen power, as well as battery technology), could reduce demand for oil and natural gas. Such initiatives or related activism aimed at responding to climate change and reducing air pollution, as well as negative investor sentiment toward our industry and the impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations, cash flows, and ability to access capital.

The oil and natural gas industry, and energy industry more broadly, is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, including technological advances in fuel economy and energy generation devices or other technological advances that could reduce demand for oil and natural gas, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement new technologies at substantial costs. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Moreover, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. 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 ours 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. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding or higher cost of capital for potential development projects, as well as the restriction, delay or cancellation of infrastructure projects and energy production activities, ultimately impacting our future financial results.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change, may also lead to increased litigation risk and regulatory, legislative, and judicial scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance or have caused other redressable injuries under federal and/or state common law. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business. In addition, various officials and candidates at the federal, state and local levels, have made climate-related pledges or proposed banning hydraulic fracturing altogether. More broadly, the enactment of climate change-related policies and initiatives across the market at the corporate level and/or investor community level may in the future result in increases in the Company's compliance costs and other operating costs and have other adverse effects (e.g., greater potential for governmental investigations or litigation). For further discussion regarding the transition risks posed to us by climate change-related regulations, policies and initiatives, see the discussion below in "—Climate change legislation or regulations restricting emissions of "greenhouse gases," or GHGs, could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects."

Increasing scrutiny and changing stakeholder expectations in respect of environmental, social and governance ("ESG") and sustainability practices may have an adverse effect on our business, financial condition and results of operations and damage our reputation.

Companies across all industries are facing increasing 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 sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on sustainability matters as they continue to evolve, meet sustainability-related goals that we have set, or if we are perceived to have not responded appropriately or quickly enough to growing concern for 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, the Company's continuing efforts to research, establish, accomplish, and accurately report on the implementation of our sustainability strategy, including any specific sustainability objectives, may also create additional operational risks and expenses and expose us to reputational, legal, and other risks. While we create and publish voluntary disclosures regarding sustainability matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring, and reporting on many sustainability matters. Further, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to sustainability matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable sustainability 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.

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 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 public company. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder trust and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

Climate change legislation or regulations pertaining to emissions of "greenhouse gases," or GHGs, could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

The EPA has adopted and implemented regulations to restrict emissions of GHGs under existing provisions of the CAA. In addition, the EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources on an annual basis in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Such climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

In August 2022, then-President Biden signed into law the Inflation Reduction Act of 2022. Among other things, the Inflation Reduction Act includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a "waste emissions charge" on certain oil and gas sources that are already required to report under 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. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. In November 2024, the EPA finalized a regulation to implement the Inflation Reduction Act's Waste Emissions Charge which became effective on January 1, 2025. The fee imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 is $900 per ton emitted over annual methane emissions thresholds, and increases to $1,200 in 2025, and $1,500 in 2026. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of these rules remain uncertain at this time. Additionally, many of the states have taken legal measures to reduce emissions of GHGs, including through the planned development of GHG emission inventories and/or regional GHGs cap and trade programs. For example, in October 2023, California enacted legislation that will ultimately require certain companies that (i) do business in California to publicly disclose their Scopes 1, 2 and 3 greenhouse gas emissions, with third party assurance of such data, and issue public reports on their climate-related financial risk and related mitigation measures and (ii) operate in California and make certain climate-related claims to provide enhanced disclosures around the achievement of climate-related claims, including the use of voluntary carbon credits to achieve such claims.

At the international level, in 2015, at COP21 the international community adopted the Paris Agreement, an international treaty aimed at addressing climate change whereby parties agreed to determine national contributions and set GHG emission reduction goals every five years beginning in 2020. In February 2021, the prior Biden Administration announced reentry of the U.S. into the Paris Agreement along with a new "nationally determined contribution" for the U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. Pursuant to its obligations as a signatory to the Paris Agreement, the United States set a target to reduce its GHG emissions by 50-52% by the year 2030 as compared with 2005 levels. At COP28, nearly 200 countries, agreed to transition away from fossil fuels while accelerating action in this decade to achieve net zero greenhouse gas emissions by 2050. Additionally, at COP28, member countries entered into an agreement that calls for actions towards achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, are to accelerate efforts towards the phase-down of unabated coal power, phase out inefficient fossil fuel subsidies, and take other measures that drive the transition away from fossil fuels in energy systems. Most recently, at the COP29, delegates approved rules to operationalize international carbon markets under Article 6 of the Paris Agreement, including a new Paris Agreement Crediting Mechanism to trade UN-approved carbon credits. Additionally, participants at COP29 representing 159 countries met to review progress toward the goals of the Global Methane Pledge and the addition of nearly $500 million in new grant funding for methane abatement. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and any similar commitment made under the UN Framework Convention on Climate Change. Despite this, various states and local governments in the U.S. have vowed to continue to enact regulations to achieve the goals of the Paris Agreement.

Additionally, on March 6, 2024, the SEC adopted the SEC Climate Rules. The SEC Climate Rules require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to, information about material climate-related risks; the registrant's governance of climate-related risks and relevant risk management processes; material climate-related targets and goals; and certain financial effects resulting from severe weather events and other natural conditions in a note to their audited financial statements (subject to de minimis thresholds). Larger registrants will also be required to disclose information about material Scope 1 and 2 greenhouse gas emissions, which will be subject to a phased-in assurance requirement. However, the SEC voluntarily stayed the SEC Climate Rules in April 2024 pending judicial review of petitions challenging the rules. We are currently evaluating the impact of the SEC Climate Rules and there remains uncertainty as to whether these rules will withstand pending and future legal challenges.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions (including those related to carbon pricing schemes) would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce and restrict our ability to execute on our business strategy, reducing our access to financial markets, or create greater potential for governmental investigations or litigation.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. For example, such effects could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, increases in our costs of operation or reductions in the efficiency of our operations, impacts on our personnel, supply chain, or distribution chain, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning. Further, energy needs could increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate changes. Increased energy use due to weather changes may require us to invest in additional equipment to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. The effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions.

The listing of a species as either "threatened" or "endangered" under the federal Endangered Species Act could result in increased costs, new operating restrictions, or delays in our operations, which could adversely affect our results of operations and financial condition.

The ESA and analogous state laws regulate activities that could have an adverse effect on threatened and endangered species. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our activities in those areas or during certain seasons, such as breeding and nesting seasons. The listing of species in areas where we operate or, alternatively, entry into certain range-wide conservation planning agreements could result in increased costs to us from species protection measures, time delays or limitations on our activities, which costs, delays or limitations may be significant and could adversely affect our results of operations and financial position. 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 and our customers' business or operations.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely for gathering and transportation services could impact the availability of those services. Any potential impact to the availability of gathering and transportation services could impact our ability to market and sell our production, which could have a material adverse effect on our business, financial condition and results of operations. See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations" and "— Other Regulation of the Oil and Natural Gas Industry" for a description of the laws and regulations that affect the third parties on whom we rely for gathering and transportation services.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water and the disposal of waste, including produced water and drilling fluids. Restrictions on the ability to obtain water or dispose of waste may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water or to dispose of or recycle water used in our development and production operations could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into "waters of the United States." Permits must be obtained to discharge pollutants to such waters and to conduct construction activities in such waters, which include certain wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells, and the disposal and recycling of produced water, drilling fluids, and other wastes, may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted. In addition, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In some jurisdictions, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity or resulted in stricter regulatory requirements relating to the location and operation of underground injection wells. For example, we conduct oil and gas drilling and production operations in the Mississippian Lime formation in Oklahoma, a high-water play, which requires us to dispose of large volumes of saltwater generated as part of our operations. In 2015, the Oklahoma Geological Survey attributed an increase in seismic activity in Oklahoma to saltwater disposal wells in the Arbuckle formation. Around the same time, the OCC, whose Oil and Gas Conservation Division regulates oil and gas operations in Oklahoma, began issuing regulations targeting saltwater disposal activities in certain areas of interest within the Arbuckle formation. The regulations include operational requirements (i.e., mechanical integrity testing of wells permitted for disposal of 20,000 or more barrels of water per day, daily monitoring and recording of well pressure and discharge volume), as well as orders to shut-in wells, reduce well depths, or decrease disposal volumes. Under these regulations, the OCC ordered us to limit the volume of saltwater disposed of in saltwater disposal wells in the Arbuckle formation and established caps for ten of our saltwater disposal wells, which caps are still in place. To ensure that we had an adequate number of wells for disposal, we secured permits for additional saltwater disposal wells outside of the Arbuckle formation. We are currently in compliance with all OCC saltwater disposal requirements, and have maintained our production base without any negative material impact. However, any additional orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations. See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations — Water Discharges and Other Waste Discharges & Spills" and "— Hydraulic Fracturing" for an additional description of the laws and regulations relating to the discharge of water and other wastes and hydraulic fracturing that affect us.

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. We routinely apply hydraulic fracturing techniques in our drilling and completion programs. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. See "Item 1. Business — Environmental, Health and Safety Matters and Regulations — Hydraulic Fracturing" for a description of the federal and state legislative and regulatory initiatives relating to hydraulic fracturing that affect us.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of prohibitions, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes further regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

The cost of decommissioning is uncertain.

We are required to maintain reserve funds to provide for the payment of decommissioning costs associated with the Beta properties. The estimates of decommissioning costs are inherently imprecise and subject to change due to changing cost estimates, oil and natural gas prices and other factors. If actual decommissioning costs exceed such estimates, or we are required to provide a significant amount of additional collateral in cash or other security as a result of a revision to such estimates, our financial condition, results of operations and cash flows may be materially adversely affected.

We are required to post cash collateral and may be in the future required to post additional collateral, pursuant to our agreements with sureties under our existing or future bonding arrangements, which may have a material adverse effect on our liquidity and our ability to execute our capital expenditure plan, our ARO plan and comply with our existing debt instruments.

Pursuant to the terms of our existing bonding arrangements with various sureties in connection with the decommissioning obligations related to our Beta properties, or under any future bonding arrangements we may enter into, we may be required to post additional collateral at any time, on demand, at the sureties' sole discretion. If additional collateral is required to support surety bond obligations, this collateral would probably be in the form of cash or letters of credit, certificate of deposit or other similar forms of liquid collateral. We cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for future bonds.

We entered into two escrow funding agreements with certain of our surety providers to fund interest-bearing escrow accounts to reimburse and indemnify the surety providers for any claims arising under the surety bonds related to the decommissioning of our Beta properties. If we fail to comply with our obligations under such escrow agreements, the surety providers may request additional collateral in the form of cash or letters of credit, certificates of deposit or other similar forms of liquid collateral. If we are required to provide additional collateral pursuant to any such request or otherwise, our liquidity position may be negatively impacted, and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing, we may be forced to reduce our capital expenditures in the current year or future years, may be unable to execute our asset retirement obligation plan or may be unable to comply with our existing debt instruments. If we are unable or unwilling to provide additional collateral, we may have to pursue alternate bonding arrangements with other sureties. See Note 7, "Asset Retirement Obligations" and Note 18, "Commitments and Contingencies — Supplemental Bond for Decommissioning Liabilities Trust Agreement" of the Notes to Consolidated Financial Statements included under Part II, "Item 8. Financial Statements and Supplementary Data," in this Annual Report for additional information.

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

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including the 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, or IDCs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged by the Tax Act, Congress could consider and could include some or all of these proposals as part of future tax reform legislation. It is unclear whether any of the foregoing or similar proposals will be considered and enacted as part of future tax reform legislation 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 have an adverse effect on the Company's financial position, results of operations and cash flows.

Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets or to render data or systems unusable; 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. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of financial assets, sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, 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. These events could lead to financial losses from remedial actions, loss of business or potential liability. In addition, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and gas production and activities could potentially result in damage or injury to people, property or the environment or lead to extended interruptions of our operations, adversely affecting our financial condition and results of operations.

We may be subject to increased permitting obligations and regulatory scrutiny as a result of the Incident.

The Incident may result in more stringent permitting obligations and regulation of our properties and other oil and gas activities, including at Beta and elsewhere, particularly relating to environmental, health and safety protection controls, oversight of oil and gas operations and required financial assurance. Regulatory or legislative action may impact the industry as a whole and could be directed specifically towards operators similarly situated to us, which could negatively impact our business.

Additionally, new regulations and legislation, as well as evolving practices, may increase the cost of compliance, require changes to our operations and strategic plans and impact our ability to capitalize on our assets.

Risks Related to the Mergers

The Mergers are subject to closing conditions and may not be completed, the Merger Agreement may be terminated in accordance with its terms, and we may be required to pay a termination fee or reimburse expenses upon termination.

The Mergers are subject to customary closing conditions that must be satisfied or waived prior to the completion of the Mergers, including the approval by our stockholders of the Stock Issuance Proposal and other customary closing conditions. Many of the closing conditions are not within our control. No assurance can be given that our stockholder approval will be obtained or that the required conditions to the Closing will be satisfied in a timely manner or at all. Any delay in completing the Mergers could cause the combined company not to realize, or to be delayed in realizing, some or all of the benefits that we expect to achieve if the Mergers are successfully completed within the expected time frame.

Additionally, either party may terminate the Merger Agreement under certain circumstances, including, among other reasons, if the Mergers are not completed by July 14, 2025. In addition, if the Merger Agreement is terminated under specified circumstances, we may be obligated to pay a termination fee of $8,500,000 or to reimburse the Acquired Companies for certain of their transaction expenses in an amount of up to $800,000.

Moreover, if the Mergers are not completed for any reason, including because stockholder approval of the Stock Issuance Proposal is not obtained, our ongoing businesses may be adversely affected and, without realizing any of the expected benefits of having completed the Mergers, we would be subject to a number of risks, including the following:

- we may experience negative reactions from the financial markets, including negative impacts on our stock price;
- we may experience negative reactions from our customers, suppliers, distributors and employees;
- we will be required to pay our costs relating to the Mergers, such as financial advisory, legal, financing and accounting costs and associated fees and expenses, whether or not the Mergers are completed;
- the market price of our Common Stock could decline to the extent that the current market price reflects a market assumption that the Mergers will not be completed;

- the Merger Agreement places certain restrictions on the conduct of our business prior to completion of the Mergers and such restrictions, the waiver of which are subject to the consent of the Acquired Companies, may prevent us from taking actions during the pendency of the Mergers that would be beneficial; and
- matters relating to the Mergers (including integration planning) will require substantial commitments of time and resources by management, which could otherwise have been devoted to day-to-day operations or to other opportunities that may have been beneficial to us as an independent company.

The consideration payable under the Merger Agreement is fixed and will not be adjusted based on our performance.

Under the Merger Agreement, the total consideration payable by us consists of 26,729,315 shares of Common Stock. The purchase price will not be adjusted for changes in the market price of our Common Stock or the economic performance of Amplify Energy or either of the Acquired Companies. If the market price of our Common Stock increases or the economic performance of the Acquired Companies relative to us improves, the consideration will not be adjusted to account for any such changes or any effective increase or decrease in the value of the Aggregate Merger Consideration issued or paid to Juniper (and/or its affiliates) under the Merger Agreement.

We will be subject to business uncertainties and contractual restrictions, including the risk of litigation, while the Mergers are pending that may cause disruption and may make it more difficult to maintain relationships with employees, suppliers or customers.

Uncertainty about the effect of the Mergers on employees, suppliers and customers may have an adverse effect on Amplify Energy and/or the Acquired Companies, which uncertainties may impair our or the Acquired Companies' ability to attract, retain and motivate key personnel until the Mergers are completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with Amplify Energy or the Acquired Companies to seek to change existing business relationships with us or the Acquired Companies.

Employee retention and recruitment may be challenging before the completion of the Mergers, as employees and prospective employees may experience uncertainty about their future roles following the Mergers. Key employees may depart or prospective key employees may fail to accept employment with us or the Acquired Companies because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company following the Mergers, any of which could have a material adverse effect on our business, financial condition and results of operations.

The pursuit of the Mergers and the preparation for the integration may place a significant burden on management and internal resources. The diversion of management's attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could have a material adverse effect on our business, financial condition and results of operations.

Until the completion of the Mergers or the termination of the Merger Agreement in accordance with its terms, we are prohibited from entering into certain transactions and taking certain actions that might otherwise be beneficial to us and our stockholders.

During the period between the date of the Merger Agreement and completion of the Mergers (or earlier termination of the Merger Agreement), the Merger Agreement restricts us from taking specified actions or from pursuing what might otherwise be attractive business opportunities or making other changes to our business, in each case without the consent of the Acquired Companies. These restrictions may prevent us from taking actions during the pendency of the Mergers that would have been beneficial. Adverse effects arising from these restrictions during the pendency of the Mergers could be exacerbated by any delays in consummation of the Mergers or termination of the Merger Agreement.

The Merger Agreement limits our ability to pursue alternatives to the Mergers and may discourage a potential competing acquirer of Amplify Energy, including the payment by Amplify Energy of a termination fee.

The Merger Agreement contains provisions that, subject to limited exceptions, restrict our ability to, among other things, directly or indirectly (i) initiate, solicit, propose, seek or knowingly encourage or knowingly facilitate (including by furnishing or providing information) any inquiries, proposals, or offers regarding, or the making of a Parent Alternative Proposal (as defined in the Merger Agreement); (ii) enter into, participate in or engage in any discussions or negotiations with respect to a Parent Alternative Proposal; (iii) furnish any information or afford access to our properties, assets or employees, in each case, in connection with or in response to a Parent Alternative Proposal; (iv) enter into any letter of intent or agreement in principle, or any other agreement providing for a Parent Alternative Proposal (other than certain permitted confidentiality agreements); (v) waive or release any person from, forbear in the enforcement of, or amend any standstill agreement or any standstill provisions of any other contract; (vi) take any action to make any "moratorium," "control share acquisition," "fair price," "supermajority," "affiliate transactions" or "business combination statute or regulation" or other similar takeover laws, including Section 203 of the Delaware General Corporation Law, inapplicable to any person or a Parent Alternative Proposal or (vii) resolve, agree, or publicly propose to take any of the foregoing actions. Further, even if the Board withdraws, modifies, or qualifies its recommendation with respect to the Stock Issuance Proposal, unless the Merger Agreement has been terminated in accordance with its terms, Amplify Energy will still be required to submit the Stock Issuance Proposal to a vote at our special meeting. In addition, the Acquired Companies generally have an opportunity to offer to modify the terms of the Mergers in response to any third-party alternative transaction proposal before the Board may withdraw, modify or qualify its recommendation with respect to the Stock Issuance Proposal. In certain circumstances, upon termination of the Merger Agreement, we will be required to pay the Acquired Companies a termination fee equal to $8,500,000. In addition, unless otherwise entitled to the termination fee, we may be obligated to pay the Acquired Companies an expense reimbursement fee up to $800,000 if the Merger Agreement is terminated in certain circumstances.

These provisions could discourage a potential third-party acquirer that might have an interest in acquiring all or a significant portion of us from considering or proposing that acquisition, even if it were prepared to pay above market value, or might otherwise result in a potential third-party acquirer proposing to pay a lower price to Amplify Energy stockholders than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances.

If the Merger Agreement is terminated and we decide to seek another merger transaction, we may not be able to negotiate or consummate a transaction with another party on terms comparable to, or better than, the terms of the Merger Agreement.

Affiliates of Amplify Energy may have interests in the Mergers that are different from, or in addition to, the interests of Amplify Energy's other stockholders.

Our officers and directors may have interests in the Mergers that are different from, or in addition to (and which may conflict with) your interests. These interests include, among other things, the expected continued employment and directorship of Martyn Willsher as chief executive officer of Amplify Energy, and the expected continued service of Christopher W. Hamm as the Chairman of the Board until such time as the Board shall vote to elect a different chairperson by a majority vote of the Board. Our Board was aware of and considered these interests, among other matters, in evaluating the Mergers, the Merger Agreement and certain other related agreements in connection with the Mergers in recommending to our stockholders that they vote in favor of the proposals presented at the Special Meeting.

Current Amplify Energy stockholders will have a reduced ownership and voting interest in Amplify Energy after the Mergers compared to their current ownership and will exercise less influence over management.

Based on the number of issued and outstanding shares of Common Stock as of January 14, 2025, it is expected that, on a fully-diluted basis, current Amplify Energy stockholders will collectively own approximately 61%, and Juniper and its affiliates will collectively own approximately 39%, of the outstanding shares of Common Stock of the combined company's outstanding equity. As a result of the Mergers, current Amplify Energy stockholders will own a smaller percentage of the combined company than they currently own of Amplify Energy, and as a result will have less influence on the management and policies of Amplify Energy post-Mergers than they now have on the management and policies of Amplify Energy, as the case may be.

The Mergers will involve substantial costs.

We have incurred and expect to incur non-recurring costs associated with the Mergers and combining the operations of the companies, as well as transaction fees and other costs related to the Mergers. These costs and expenses include fees paid to legal, financial and accounting advisors, regulatory and public relations advisors, filing fees, printing costs and other costs and expenses. A significant portion of these transaction costs is contingent upon the Closing occurring, although some have been and will be incurred regardless of whether the Mergers are consummated.

In addition, the combined company may incur significant restructuring and integration costs in connection with the integration of Amplify Energy and the Acquired Companies and the execution of our business plan, including costs relating to formulating and implementing integration plans and eliminating duplicative costs. The costs related to restructuring will be expensed as a cost of the ongoing results of operations of either us or the combined company. There are processes, policies, procedures, operations, technologies and systems that must be integrated in connection with the Mergers and the integration of each of the Acquired Companies' businesses. While we have assumed a certain level of expenses would be incurred to integrate Amplify Energy and the Acquired Companies and achieve synergies and efficiencies and we continue to assess the magnitude of these costs, many of these expenses are, by their nature, difficult to estimate accurately, and there are many factors beyond our control that could affect the total amount or timing of these costs. Although we expect that the elimination of duplicative costs, as well as the realization of strategic benefits, additional income, synergies and other efficiencies should allow the combined company to offset integration-related costs over time, this net benefit may not be achieved in the near term, or at all.

Securities class action and derivative lawsuits may be filed against us, or against our directors, challenging the Mergers, and an adverse ruling in any such lawsuit may prevent the Mergers from becoming effective or from becoming effective within the expected time frame.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger or other similar agreements. Mergers like the Mergers are frequently subject to litigation or other legal proceedings, including actions alleging that our Board breached their fiduciary duties to our stockholders by entering into the Merger Agreement. We cannot provide assurance that such litigation or other legal proceedings will not be brought. If litigation or other legal proceedings are in fact brought against us, or against our Board, we will defend against it, but might not be successful in doing so. An adverse outcome in such matters, as well as the costs and efforts of a defense even if successful, could have a material adverse effect on the business, results of operation or financial position of us or the combined company, including through the possible diversion of company resources or distraction of key personnel.

Lawsuits that may be brought against us, the Acquired Companies or our or their directors could also seek, among other things, injunctive relief or other equitable relief, including a request to enjoin us from consummating the Mergers. One of the conditions to the Closing are that no order, award or judgment by any court or other tribunal of competent jurisdiction has been entered and continues to be in effect and no law has been adopted or is effective, in either case, that prohibits or makes illegal the Closing. Consequently, if a plaintiff is successful in obtaining an order, award or judgment prohibiting completion of the Mergers, that order, award or judgment may delay or prevent the Mergers from being completed within the expected time frame or at all, which may adversely affect our business, financial position and results of operations.

We expect to refinance substantial indebtedness of the Acquired Companies in connection with the Mergers, which combined with our current debt may limit our financial flexibility and adversely affect our financial results.

In connection with the Mergers, Amplify Energy expects to refinance a substantial portion of its outstanding debt and approximately $133 million in principal amount of the Acquired Companies' outstanding debt. There is no guarantee that Amplify Energy will be able to execute the refinancing on favorable terms or at all. If Amplify Energy is unable to refinance the debt on favorable terms, its financial condition could be adversely affected. If Amplify Energy is unable to complete a sufficient refinancing at all, it may not be able to complete the Mergers.

In addition, if Amplify Energy is able to execute the refinancing, the combined company's level of indebtedness following the completion of the Mergers could have important consequences. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- impair our ability to obtain additional debt or equity financing in the future for working capital, capital expenditures, development of estimated proved undeveloped reserves, development and acquisition projects, acquisitions or general corporate or other purposes;
- require us to dedicate a material portion of our cash flows to the payment of principal and interest on our indebtedness, thereby reducing the availability of our cash flows to fund working capital needs, capital expenditures, development of estimated PUDs, development and acquisition projects, acquisitions and other general corporate purposes;
- expose us to variable interest rate risk to the extent of any borrowings under our existing and any assumed credit facilities;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- place us at a disadvantage compared to our competitors that have less indebtedness; and
- limit our ability to adjust to changing market conditions.

Any of these risks could materially impact our ability to fund our operations or limit our ability to expand the combined business, which could have a material adverse effect on the combined company, its financial condition and results of operations.

Combining the businesses of Amplify Energy, NPOG and COG may be more difficult, costly or time-consuming than expected and the combined company may fail to realize the anticipated synergies and other benefits of the Mergers, which may adversely affect the combined company's business results and negatively affect the value of our Common Stock following the consummation of the Mergers.

Amplify Energy and each of the Acquired Companies have operated and, until the completion of the Mergers will continue to operate, independently. The success of the Mergers will depend on, among other things, the ability of Amplify Energy and the Acquired Companies to combine their businesses in a manner that facilitates growth opportunities and realizes expected cost savings. We have entered into the Merger Agreement because we believe that the mergers contemplated by the Merger Agreement are fair to and in the best interests of our stockholders and that combining the businesses of Amplify Energy and the Acquired Companies will produce benefits as well as cost savings and other cost and capital expenditure synergies.

Following the Closing, Amplify Energy and the Acquired Companies must successfully combine their respective businesses in a manner that permits these benefits to be realized. For example, the following issues, among others, must be addressed in integrating the operations of the companies in order to realize the anticipated benefits of the Mergers:

- combining the companies' operations and corporate functions;
- combining the businesses of Amplify Energy and the Acquired Companies and meeting the capital requirements of the combined company, in a manner that permits the combined company to achieve any cost savings or other synergies anticipated to result from the Mergers, the failure of which would result in the anticipated benefits of the Mergers not being realized in the time frame currently anticipated or at all;
- integrating personnel from the companies;
- integrating and unifying our reserves and the development of our new PUDs;
- identifying and eliminating underperforming or uncertain wells;
- harmonizing the companies' operating practices, employee development and compensation programs, internal controls and other policies, procedures and processes;
- maintaining existing agreements with customers, suppliers, distributors and vendors, avoiding delays in entering into new agreements with prospective customers, suppliers, distributors and vendors, and leveraging relationships with such third parties for the benefit of the combined company;
- addressing possible differences in business backgrounds, corporate cultures and management philosophies;
- consolidating the companies' administrative and information technology infrastructure;
- coordinating distribution and marketing efforts; and
- effecting actions that may be required in connection with obtaining regulatory or other governmental approvals.

It is possible that the integration process could result in the loss of key employees of Amplify Energy or the Acquired Companies, the loss of customers, the disruption of either Amplify Energy's or the Acquired Companies' ongoing businesses, inconsistencies in standards, controls, procedures and policies, unexpected integration issues, higher than expected integration costs and an overall post-completion integration process that takes longer than originally anticipated. In addition, the actual integration may result in additional and unforeseen expenses. If the combined company is not able to adequately address integration challenges, we may be unable to successfully integrate operations and the anticipated benefits of the integration plan may not be realized.

In addition, the combined company must achieve the anticipated growth and cost savings without adversely affecting current revenues and investments in future growth. If the combined company is not able to successfully achieve these objectives, the anticipated synergies and other benefits of the Mergers may not be realized fully, or at all, or may take longer to realize than expected. Additionally, we may inherit from the Acquired Companies legal, regulatory, and other risks that occurred prior to the Mergers, whether known or unknown to us, which may be material to the combined company. Actual growth, cost and capital expenditure synergies and other cost savings, if achieved, may be lower than what we expect and may take longer to achieve than anticipated. Moreover, at times the attention of the combined company's management and resources may be focused on the integration of the businesses of the company and diverted from day-to-day business operations or other opportunities that may have been beneficial to such company, which may disrupt the combined company's ongoing businesses.

An inability to realize the full extent of the anticipated benefits of the Mergers, as well as any delays encountered in the integration process, could have an adverse effect upon the revenues, level of expenses and operating results of the combined company, which may adversely affect the value of our Common Stock following the consummation of the Mergers. Moreover, if the combined company is unable to realize the full strategic and financial benefits currently anticipated from the Mergers, Amplify Energy stockholders will have experienced substantial dilution of their ownership interests without receiving any commensurate benefit, or only receiving part of the commensurate benefit to the extent the combined company is able to realize only part of the strategic and financial benefits currently anticipated from the Mergers.

The combined company may not be able to retain customers, suppliers or distributors, or customers, suppliers or distributors may seek to modify contractual relationships with the combined company, which could have an adverse effect on the combined company's business and operations. Third parties may terminate or alter existing contracts or relationships with the combined company.

As a result of the Mergers, the combined company may experience impacts on relationships with customers, suppliers and distributors that may harm the combined company's business and results of operations. Certain customers, suppliers or distributors may seek to terminate or modify contractual obligations following the Mergers whether or not contractual rights are triggered as a result of the Mergers. There can be no guarantee that customers, suppliers and distributors will remain with or continue to have a relationship with the combined company or do so on the same or similar contractual terms following the Mergers. If any customers, suppliers or distributors seek to terminate or modify contractual obligations or discontinue the relationship with the combined company, then the combined company's business and results of operations may be harmed. If the combined company's suppliers were to seek to terminate or modify an arrangement with the combined company, then the combined company may be unable to procure necessary supplies from other suppliers in a timely and efficient manner and on acceptable terms, or at all.

We and each of the Acquired Companies also have contracts with third parties which may require consent from these parties in connection with the Mergers, or which may otherwise contain limitations applicable to such contracts following the Mergers. If these consents cannot be obtained, the combined company may suffer a loss of potential future revenue, incur costs and lose rights that may be material to the combined company's business. In addition, third parties with whom we or either of the Acquired Companies currently have relationships may terminate or otherwise reduce the scope of their relationship in anticipation of the Mergers. Any such disruptions could limit the combined company's ability to achieve the anticipated benefits of the Mergers. The adverse effect of any such disruptions could also be exacerbated by a delay in the completion of the Mergers or by a termination of the Merger Agreement.

The Acquired Companies are currently not U.S. public reporting companies, and the obligations associated with integrating into a public company may require significant resources and management attention.

The Acquired Companies are, and prior to the consummation of the Mergers will remain, private companies that are not subject to reporting requirements and do not have accounting personnel specifically employed to review internal controls over financial reporting. Upon completion of the Mergers, the Acquired Companies will become subject to the rules and regulations established from time to time by the SEC and NYSE. In addition, as a public company, we are required to document and test our internal controls over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002, so that our management can certify as to the effectiveness of our internal control over financial reporting in connection with the annual report. The Acquired Companies are required to be included in the scope of our internal control over financial reporting in the annual report to be filed with the SEC for the fiscal year following the fiscal year in which the Mergers are consummated and thereafter, which requires us to make and document significant changes to our internal controls over financial reporting. Bringing the Acquired Companies into compliance with these rules and regulations and integrating the Acquired Companies into our current compliance and accounting system may increase our legal and financial compliance costs, make some activities more difficult, time-consuming or costly and increase demand on our systems and resources. Furthermore, the need to establish the necessary corporate infrastructure to integrate the Acquired Companies may divert management's attention from implementing our growth strategy, which could prevent us from improving our business, financial condition and results of operations. However, the measures we take may not be sufficient to satisfy our obligations as a public company. If we do not continue to develop and implement the right processes and tools to manage our changing enterprise upon the Mergers and maintain our culture, our ability to compete successfully and achieve our business objectives could be impaired, which could negatively impact our business, financial condition and results of operations. In addition, we cannot predict or estimate the amount of additional costs we may incur to bring the Acquired Companies into compliance with these requirements. We anticipate that these costs will materially increase our general and administration expenses. In addition, bringing the Acquired Companies into compliance with these rules and regulations will increase our legal and financial compliance costs and will make some activities more time-consuming and costly. These additional obligations could have a material adverse effect on our business, financial condition, results of operations and cash flow.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Our cybersecurity strategy prioritizes prevention, detection, analysis and response to known, anticipated or unexpected threats, effective management of security risks and resiliency against incidents. Our cybersecurity risk management processes include technical security controls, policy enforcement mechanisms, monitoring systems, contractual arrangements, tools and related services from third-party providers, and management oversight to assess, identify and manage risks from cybersecurity threats. We implement risk-based controls to protect our information, the information of our customers and other third parties, our information systems, our business operations, and our produced products and related services. We have adopted security-control principles primarily based on the National Institute of Standards and Technology Cybersecurity Framework (NIST). We also leverage industry and government associations, third-party benchmarking, internal and external Company audit results, threat intelligence feeds, and other similar resources to form our cybersecurity processes and allocate resources.

We maintain an information security program that includes physical, administrative and technical safeguards, and we maintain plans and procedures whose objective is to help us prevent, while timely and effectively responding to, cybersecurity threats or incidents, including those from third-party service providers who have access to our systems, data or are critical to our continued business operations. Through our cybersecurity risk management process, which is overseen by the Amplify Information Technology Steering Committee (the "Steering Committee"), we continuously monitor cybersecurity vulnerabilities and potential attack vectors and evaluate the potential operational and financial effects of any threat and of cybersecurity risk countermeasures made to defend against such threats. This process has been integrated into the Company's Risk Management Program, and we have integrated Cyber Incident Response planning into our Business Continuity Program. In addition, we routinely engage third-party consultants to assist us in assessing, enhancing, implementing, and monitoring our cybersecurity risk management programs and responding to any incidents. We also carry insurance that provides protection against the potential losses arising from a cybersecurity incident. We provide monthly cybersecurity awareness and weekly phishing simulations, data protection modules, tabletop exercises, as well as more contextual and personalized modules for targeted users and roles.

Our Steering Committee was established to further strengthen our cybersecurity risk management activities across the Company, including the prevention, detection, mitigation and remediation of cybersecurity incidents. The Steering Committee has primary management oversight responsibility for assessing and managing risks from cybersecurity threats and is responsible for developing and coordinating enterprise cybersecurity policies and strategies and for providing guidance to key management and oversight bodies. Our Vice President of Information Technology, who has nearly two decades of information technology and cybersecurity risk management experience in the oil and natural gas industry, serves as the chair of the Steering Committee. The Steering Committee includes senior executives and managers, with significant risk management expertise, from multiple areas of the business. The Steering Committee meets quarterly and reports to senior management regarding the progress of specific cybersecurity objectives. Cross-enterprise action teams will be formed, as needed, to manage and implement key decisions of the Steering Committee. A strong partnership exists between our information technology, finance, operations, internal audit, and legal departments for the purpose of addressing identified issues in a timely manner and reporting incidents as required.

The Nominating & Governance Committee, which is comprised entirely of independent directors, has primary responsibility for oversight of the Company's initiatives, policies and performance regarding risk management matters, including information security, cybersecurity, business continuity and data protection and privacy. Committee members have extensive experience working for and/or serving on the boards of directors of publicly traded companies and are experienced in overseeing cybersecurity and information security risks, understanding the cybersecurity threat landscape and/or assessing emerging cybersecurity risks. The Nominating & Governance Committee generally meets at least quarterly and as frequently as circumstances dictate. Members of senior management, representing a variety of teams and functions including information technology, operations, finance and legal, routinely provide updates regarding assessments of cyber risks, the threat landscape, and the Company's cybersecurity risk mitigation and governance strategies. The Nominating & Governance Committee and members of senior management brief the entire board, as necessary, on cybersecurity matters discussed during committee meetings.

While some of our third-party service providers have experienced cybersecurity incidents and have experienced threats to their data and systems, as of the date of this Annual Report, we are not aware of any cybersecurity threats that have materially affected or are reasonably likely to materially affect us. However, we face certain ongoing risks from cybersecurity threats, that, if realized, may, among other things, cause material disruptions to our operations, which may materially affect us, including our business strategy, results of operations, and/or financial condition. For more information about these risks, see the risk factor titled, "Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions" under Item 1A of Part I of this Annual Report.

ITEM 2. PROPERTIES

Information regarding our properties is contained in "Item 1. Business — Our Areas of Operation" and "—Our Oil and Natural Gas Data" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations" contained herein.

ITEM 3. LEGAL PROCEEDINGS

As part of our normal business activities, we may be named as defendants in other litigation and legal proceedings, including those arising from regulatory and environmental matters. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We are not aware of any litigation, pending or threatened, that we believe will have a material adverse effect on our financial position, results of operations or cash flows outside of what has been disclosed for the Incident. The Company accrued $1.1 million at December 31, 2024, in regard to our litigation and legal proceedings related to the Incident.

For additional information regarding legal proceedings, see Note 18, "Commitments and Contingencies — Litigation and Environmental" of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report and "Part II – Item 1A. Risk Factors — Risks Related to our Business — We may be subject to increased permitting obligations and regulatory scrutiny as a result of the Incident" which are incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

Our Common Stock is listed on the NYSE under the trading symbol "AMPY" and has been trading since August 7, 2019.

As of February 28, 2025, we had 40,332,937 shares of our Common Stock outstanding. As of February 28, 2025, we had twenty-one record holders of our Common Stock, based on information provided by our transfer agent.

Dividends Policy

While we may decide to pay cash dividends in the future, we have not paid, nor do we currently intend to pay, any cash dividends on our Common Stock. Future dividends, if any, are subject to the terms of our Revolving Credit Facility and discretionary approval by the Board.

Securities Authorized for Issuance Under Equity Compensation Plan

See the information incorporated by reference in "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" for information regarding shares of our Common Stock authorized for issuance under our stock compensation plans, which information is incorporated herein by reference.

Issuer Purchases of Equity Securities

The following sets forth information with respect to the Company's repurchases of shares of its Common Stock during the fourth quarter of 2024.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (1) (In thousands)
Common Shares Repurchased (1)				
October 1, 2024 - October 31, 2024	2,000	$ 6.66	—	n/a
November 1, 2024 - November 30, 2024	—	$ —	—	n/a
December 1, 2024 - December 31, 2024	—	$ —	—	n/a

(1) Common shares are generally net-settled by shareholders to cover the required withholding tax upon vesting. The Company repurchased the remaining vesting shares on the vesting date at current market price. See Note 12, "Equity-based Awards" of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report, which is incorporated herein by reference.

ITEM 6. Reserved

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

Management's Discussion and Analysis ("MD&A") of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" contained herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are discussed in "Risk Factors" contained in Part I, Item 1A. of this report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Forward-Looking Statements" in the front of this Annual Report.

Overview

We operate in one reportable segment engaged in the acquisition, development, exploitation and production of oil and natural gas properties. Our management evaluates performance based on the reportable business segment as the economic environments are not different within the operation of our oil and natural gas properties. Our business activities are conducted through OLLC, our wholly owned subsidiary, and its wholly owned subsidiaries. Our assets consist primarily of producing oil and natural gas properties located in Oklahoma, the Rockies ("Bairoil"), federal waters offshore Southern California ("Beta"), East Texas/North Louisiana and Eagle Ford. Most of our oil and natural gas properties are located in large, mature oil and natural gas reservoirs.

Production and Operation Update

Total production for the Company in 2024 was composed of approximately 43% oil, 39% natural gas and 18% NGLs compared to 37% oil, 45% natural gas and 18% NGLs in 2023. The change in our oil production was primarily related to Beta restarting operations in April 2023 and the development of wells at Beta. We had a decrease of 2% in oil and natural gas sales primarily due to lower volumes. Average realized sales price per Boe was $39.61 for 2024 compared to $38.54 for 2023.

Our total estimated proved reserves decreased to 93.0 MMBoe in 2024 compared to 98.1 MMBoe in 2023. The decrease was primarily due to changes in commodity prices and 2024 production roll off, partially offset by changes in development plans specifically related to Beta.

As of December 31, 2024, we are the operator of record for properties containing 92% of our total estimated proved reserves.

Recent Developments

East Texas Haynesville Monetization

In December 2024, we sold certain rights, title and interest in assets located in East Texas to a third party. We recorded a gain of approximately $1.4 million.

In January 2025, we purchased and sold certain rights, title and interest in assets in East Texas from a third party, whereby we received net proceeds of $6.2 million.

Merger with Juniper Capital

On January 14, 2025, we entered into the Merger Agreement with the Merger Subs, the Acquired Companies, and, solely for the limited purposes set forth in the Merger Agreement, Juniper and the Specified Company Entities set forth on Annex A thereto, pursuant to which, at the Effective Time, (a) NPOG will merge with and into First Merger Sub, with NPOG surviving the merger as an indirect, wholly owned subsidiary of the Company and (b) COG will merge with and into Second Merger Sub, with COG surviving the merger as an indirect, wholly owned subsidiary of the Company, in each case, subject to the terms and conditions of the Merger Agreement.

Subject to the terms and conditions of the Merger Agreement, at the Effective Time, all of the issued and outstanding limited liability company interests of each of the Acquired Companies will automatically be converted into the right to receive the Aggregate Merger Consideration. Following the Effective Time, the Company's existing stockholders and the Acquired Companies' existing equityholders are expected to own approximately 61% and 39%, respectively, of the combined company's outstanding equity.

Mr. Christopher W. Hamm will serve as Chairman of the Board, and Mr. Martyn Willsher will continue to serve as the Chief Executive Officer of the Company after the Effective Time. The Merger Agreement provides that the Board will consist of the following seven members: Martyn Willsher, Christopher W. Hamm, Deborah G. Adams, James E. Craddock, Vidisha Prasad, Edward Geiser and Josh Schmidt. Further, Josh Schmidt will be appointed as Chairman of the Compensation Committee, and Edward Geiser will be appointed as a member of the Nominating and Governance Committee.

The Merger Agreement contains customary representations, warranties and covenants of the Company and the Acquired Companies, including covenants relating to the conduct of the business of both the Company and the Acquired Companies from the date of signing the Merger Agreement through the Closing, obtaining the requisite approval of the stockholders of the Company and maintaining the listing of the Common Stock on the NYSE. Under the terms of the Merger Agreement, the Company has also agreed not to solicit from any person an acquisition proposal for the Company.

In connection with the Mergers, the Company will seek the approval of the Company's stockholders of the Stock Issuance Proposal. The Board has agreed to recommend the approval of the Stock Issuance Proposal to our stockholders and to solicit proxies in support of the approval of the Stock Issuance Proposal at a meeting of the stockholders (the "Stockholders Meeting") to be held for that purpose.

The Closing is subject to various customary closing conditions, including, among other things, (a) the receipt of approval of the Stock Issuance Proposal by the affirmative vote of at least a majority of the votes cast in person or represented by proxy at the Stockholders Meeting by the holders of Common Stock entitled to vote thereon (the "Amplify Stockholder Approval"), (b) the receipt of certain specified consents, and (c) the approval for listing by the NYSE for the shares of Common Stock to be issued in connection with the Mergers.

The Merger Agreement also provides each of the Company and the Acquired Companies with certain termination rights including, among other things, termination: (a) by the Acquired Companies or Amplify Energy if Amplify Energy fails to obtain the Amplify Stockholder Approval; (b) by Amplify Energy or the Acquired Companies, if Amplify Energy or either of the Acquired Companies breaches or fails to perform any of its or their respective representations, warranties or covenants in the Merger Agreement and such breach cannot be or is not timely cured in accordance with the terms of the Merger Agreement and such breach or failure to perform would cause the applicable closing condition not to be satisfied; (c) by the Acquired Companies, in the event the Board effects a Parent Change in Recommendation (as defined in the Merger Agreement) prior to the Amplify Stockholder Approval being obtained or if Amplify Energy is in violation of the covenant to not solicit alternative business combination proposals from third parties in any material respect; or (d) by Amplify Energy, if the Acquired Companies are in violation of the covenant to not solicit alternative business combination proposals from third parties in any material respect.

In the event that a Parent Alternative Proposal (as defined in the Merger Agreement) is publicly submitted or proposed to the Board prior to, and not withdrawn at the time of the Stockholders Meeting, the Merger Agreement is terminated by the Acquired Companies in accordance with clause (b) above or by either Amplify Energy or the Acquired Companies in accordance with clause (a) above or as a result of the failure to close the Mergers on or before July 14, 2025 (the "Outside Date"), and Amplify Energy enters into a definitive agreement with respect to, or consummates, a Parent Alternative Proposal within 12 months following termination of the Merger Agreement, Amplify Energy will be required to pay the Acquired Companies a termination fee of $8,500,000 (the "Amplify Termination Fee"). Amplify Energy will also be required to pay the Acquired Companies the Amplify Termination Fee in the event the Merger Agreement is terminated by the Acquired Companies in accordance with clause (c) above. In the event that Amplify terminates the Merger Agreement in accordance with clause (d) above, the Acquired Companies will be required to (or will cause the Specified Company Entities to) pay Amplify a termination fee of $5,500,000 (the "Acquired Companies' Termination Fee" and, together with the Amplify Termination Fee, the "Termination Fees"). If the Merger Agreement is terminated by any party in accordance with clause (a) or by the Acquired Companies in accordance with clause (b) above and the Amplify Termination Fee is not otherwise payable in accordance with the terms and conditions of the Merger Agreement, then Amplify Energy will be required to reimburse the Acquired Companies' incurred expenses, up to a maximum aggregate amount of $800,000. If the Merger Agreement is terminated by Amplify Energy in accordance with clause (b) above and the Acquired Companies' Termination Fee is not otherwise payable in accordance with the terms and conditions of the Merger Agreement, then the Acquired Companies will be required to (or will cause the Specified Company Entities to) reimburse Amplify Energy's incurred expenses, up to a maximum aggregate amount of $1,250,000. In addition to the foregoing termination rights, the Merger Agreement may be terminated by either Amplify Energy or the Acquired Companies if the Mergers have not been consummated on or prior to the Outside Date or if a governmental entity issues a final, non-appealable order or decree permanently restraining, enjoining or prohibiting the Mergers. The parties may also mutually agree to terminate the Merger Agreement.

If the Board effects a Parent Change in Recommendation prior to the Stockholders Meeting, Amplify Energy will, unless the Acquired Companies terminate the Merger Agreement, be required to submit the approval of the Amplify Stock Issuance to a vote of Amplify Energy's stockholders at the Stockholders Meeting notwithstanding the Parent Change in Recommendation. Neither Amplify Energy nor the Acquired Companies are able to terminate the Merger Agreement in order to accept an alternative business combination proposal.

The Merger Agreement provides that, during the period from the date of the Merger Agreement until the Effective Time, each of Amplify Energy and the Acquired Companies will be subject to certain restrictions on their ability to solicit or respond to alternative business combination proposals from third parties, to provide non-public information to third parties and to engage in discussions with third parties regarding alternative business combination proposals, subject to customary exceptions.

The Merger Agreement contains customary representations, warranties and covenants for a transaction of this nature. The Merger Agreement also contains customary pre-closing covenants, including the obligations of Amplify Energy and the Acquired Companies to conduct their respective businesses in the ordinary course, consistent with past practice, and to refrain from taking certain specified actions without the consent of the other party.

No Offer or Solicitation. This section of the Annual Report relates to a proposed business combination transaction between the Company and the Acquired Companies. This communication is for informational purposes only and does not constitute an offer to sell or the solicitation of an offer to buy any securities or a solicitation of any vote or approval, in any jurisdiction, pursuant to the business combination transaction or otherwise, nor shall there be any sale, issuance, exchange or transfer of the securities referred to in this document in any jurisdiction in contravention of applicable law. No offer of securities shall be made except by means of a prospectus meeting the requirements of Section 10 of the Securities Act of 1933, as amended.

Important Additional Information Regarding the Mergers Will Be Filed With the SEC. In connection with the proposed Mergers, the Company has filed a definitive proxy statement. The definitive proxy statement will be sent to the stockholders of the Company. The Company may also file other documents with the SEC regarding the Mergers. INVESTORS AND SECURITY HOLDERS OF AMPLIFY ENERGY ARE ADVISED TO CAREFULLY READ THE DEFINITIVE PROXY STATEMENT AND ANY OTHER RELEVANT MATERIALS FILED WITH THE SEC WHEN THEY BECOME AVAILABLE BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT THE MERGERS, THE PARTIES TO THE MERGERS AND THE RISKS ASSOCIATED WITH THE MERGERS. Investors and security holders may obtain a free copy of the definitive proxy statement and other relevant documents filed by Amplify Energy with the SEC from the SEC's website at www.sec.gov. Security holders and other interested parties will also be able to obtain, without charge, a copy of the definitive proxy statement and other relevant documents (when available) by (1) directing your written request to: 500 Dallas Street, Suite 1700, Houston, Texas or (2) contacting our Investor Relations department by telephone at (832) 219-9044 or (832) 219-9051. Copies of the documents filed by the Company with the SEC will be available free of charge on the Company's website at http://www.amplifyenergy.com.

Participants in the Solicitation. Amplify Energy and certain of its respective directors, executive officers and employees may be considered participants in the solicitation of proxies in connection with the proposed transaction. Information regarding the persons who may, under the rules of the SEC, be deemed participants in the solicitation of the stockholders of Amplify Energy in connection with the transaction, including a description of their respective direct or indirect interests, by security holdings or otherwise, is included in the definitive proxy statement filed with the SEC. Additional information regarding the Company's directors and executive officers is also included in Amplify's Notice of Annual Meeting of Stockholders and 2024 Proxy Statement, which was filed with the SEC on April 5, 2024. These documents are available free of charge as described above.

Industry Trends

For a discussion of how industry trends have affected and may continue to affect our business and financial condition, see the discussion under the heading "Industry Trends" in Part I, Item 1 of this report, as well as the Risk Factors set forth in Part I, Item 1A of this report.

Business Environment and Operational Focus

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including: (i) production volumes; (ii) realized prices on the sale of our production; (iii) cash settlements on our commodity derivatives; (iv) lease operating expense; (v) gathering, processing and transportation; (vi) general and administrative expense; and (vii) Adjusted EBITDA.

Production Volumes

Production volumes directly impact our results of operations. For more information about our volumes, see "— Results of Operations" below.

Realized Prices on the Sale of Oil and Natural Gas

We market our oil and natural gas production to a variety of purchasers based on regional pricing. The relative prices of oil and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. In addition, realized prices are heavily influenced by product quality and location relative to consuming and refining markets.

Natural Gas. The NYMEX-Henry Hub future price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices realized from the sale of natural gas can differ from the quoted NYMEX-Henry Hub price as a result of quality and location differentials. Quality differentials to NYMEX-Henry Hub prices result from: (1) the Btu content of natural gas, which measures its heating value, and (2) the percentage of sulfur, CO_2 and other inert content by volume. Natural gas with a high Btu content ("wet" natural gas) sells at a premium to natural gas with low Btu content ("dry" natural gas) because it yields a greater quantity of NGLs. Natural gas with low sulfur and CO_2 content sells at a premium to natural gas with high sulfur and CO_2 content because of the added cost required to separate the sulfur and CO_2 from the natural gas to render it marketable. Wet natural gas may be processed in third-party natural gas plants, where residue natural gas as well as NGLs are recovered and sold. At the wellhead, our natural gas production typically has an average energy content greater than 1,000 Btu. The dry natural gas residue from our properties is generally sold based on index prices in the region from which it is produced.

Location differentials to NYMEX-Henry Hub prices result from variances in transportation costs based on the produced natural gas' proximity to the major consuming markets to which it is ultimately delivered. Historically, these index prices have generally been at a discount to NYMEX-Henry Hub natural gas prices.

Oil. The NYMEX-WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The ICE Brent futures price is a widely used global price benchmark for oil. The actual prices realized from the sale of oil can differ from the quoted NYMEX-WTI price as a result of quality and location differentials. Quality differentials result from the fact that crude oils differ from one another in their molecular makeup, which plays an important part in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: (1) the oil's API gravity and (2) the oil's percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value and, therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content ("sweet" oil) is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil ("sour" oil).

Location differentials result from variances in transportation costs based on the produced oil's proximity to the major consuming and refining markets to which it is ultimately delivered. Oil that is produced close to major consuming and refining markets, such as near Cushing, Oklahoma, is in higher demand as compared to oil that is produced farther from such markets. Consequently, oil that is produced close to major consuming and refining markets normally realizes a higher price (i.e., a lower location differential).

The oil produced from our onshore properties is a combination of sweet and sour oil, which varies by location. This oil is typically sold at the NYMEX-WTI price, adjusted for quality and transportation differential, depending primarily on location and purchaser. The oil produced from our offshore properties is heavy and sour oil and was sold based on refiners' posted prices for California Midway-Sunset for the year ended December 31, 2024. Effective January 1, 2025, offshore production will be sold based on posted prices for ICE Brent.

Price Volatility. In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. The following table shows the low and high commodity future index prices for the periods indicated:

	High	Low
For the Year Ended December 31, 2024:		
NYMEX-WTI oil future price range per Bbl	$ 86.91	$ 65.75
NYMEX-Henry Hub natural gas future price range per MMBtu	$ 3.95	$ 1.58
ICE Brent oil future price range per Bbl	$ 91.17	$ 69.19

Commodity Derivative Contracts. Our hedging activities are intended to support oil, natural gas and NGL prices at targeted levels and to manage our exposure to commodity price fluctuations. The covenants in our Revolving Credit Facility require us to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 50%−75% of our estimated production from proved developed producing reserves over a one-to-three-year period at any given point of time. We may, however, from time-to-time hedge more or less than this approximate range. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes when circumstances suggest that it is prudent to do so. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Principal Components of Cost Structure

- *Lease operating expense*. These are the day-to-day costs incurred to maintain production of our natural gas, NGLs and oil. Such costs include utilities, direct labor, water injection and disposal, the cost of CO_2 injection, chemicals, materials and supplies, compression, repairs and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services and activities performed during a specific period.

- *Gathering, processing and transportation.* These are costs incurred to deliver production of our natural gas, NGLs and oil to the market. Cost levels of these expenses can vary based on the volume of natural gas, NGLs and oil production.

- *Taxes other than income*. These consist of production, ad valorem, NOx credits, waste emission charges and franchise taxes. Production taxes are paid on produced natural gas, NGLs and oil based on a percentage of market prices and at fixed per unit rates established by federal, state or local taxing authorities. We take advantage of credits and exemptions in the various taxing jurisdictions where we operate. Ad valorem taxes are generally tied to the valuation of the oil and natural gas properties. Franchise taxes are privilege taxes levied by states that are imposed on companies, including limited liability companies and partnerships, which gives the businesses the right to be chartered or operate within that state.

- *Depreciation, depletion and amortization*. Depreciation, depletion and amortization ("DD&A") includes the systematic expensing of the capitalized costs incurred to acquire, exploit and develop oil and natural gas properties. As a "successful efforts" company, all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are depleted using the units of production method.

- *Impairment expense.* Proved properties are impaired whenever the net carrying value of the properties exceed their estimated undiscounted future cash flows. Unproved properties are impaired based on time or geologic factors.

- *General and administrative expense*. These costs include overhead, including payroll and benefits for employees, costs of maintaining headquarters, costs of managing production and development operations, compensation expenses associated with certain long-term incentive-based plans, audit and other professional fees and legal compliance expenses.

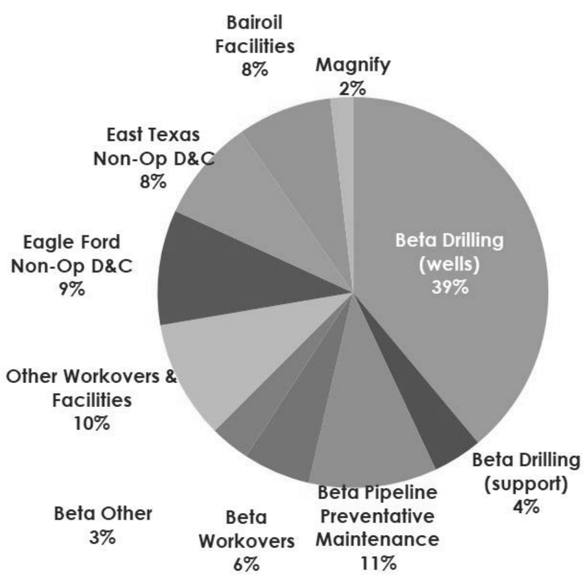
- *Interest expense, net.* Historically, we have financed a portion of our working capital requirements, capital development and acquisitions with borrowings under our Revolving Credit Facility. We incur interest expense that is affected by both fluctuations in interest rates and financing decisions. These costs also include capitalized interest, the amortization and write off of deferred financing costs and the amortization of surety bonds.

- *Income tax expense.* We are a corporation subject to federal and certain state income taxes. We are subject to the Texas margin tax for activities in the State of Texas.

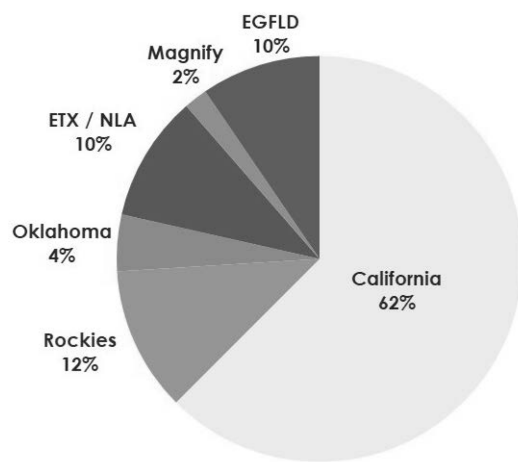
Outlook

Based on our current plans, our capital expenditure program for the full year 2025 is expected to be approximately $70.0 million to $80.0 million. The charts below detail the allocation of capital across our asset base and by investment type based on the midpoint of our 2025 capital expenditure range.

2025 CAPEX by Investment



2025 CAPEX by Area



As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices and other factors. We anticipate funding our 2025 capital program from internally generated cash flow.

Critical Accounting Policies and Estimates

The methods, estimates and judgments we use in applying our critical accounting policies have a significant impact on the results we report in our Consolidated Financial Statements. We evaluate our estimates and judgments on an on-going basis. We base our estimates on historical experience and on assumptions that we believe to be reasonable under the circumstances. Our experience and assumptions form the basis for our judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results may vary from what we anticipate and different assumptions or estimates about the future could change our reported results.

Oil and Natural Gas Properties. We use the successful efforts method of accounting for our oil and natural gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense.

We review the carrying value of our oil and natural gas properties, including support equipment for impairments quarterly or when events and circumstances indicate the carrying value of our properties may not be recoverable. Such indications could be the result of downward revisions of the reserve estimates, less than expected production or drilling results, higher operating and development costs, or lower commodity prices. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

We believe accounting for oil and natural gas properties is a critical accounting estimate because the policies discussed above impact the carrying value of our properties and involve significant judgments about the impact of future events on our estimated cash flows. Future events and circumstances currently unknown to us could require future impairments to our properties and materially change the carrying value of our properties.

***Oil and Natural Gas Reserves*.** Proved oil and natural gas reserves are estimated in accordance with the rules established by the SEC and FASB. The rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalation in future years except by contractual arrangements. Our reserve estimates are prepared by our reserve engineers and audited by independent engineers.

Our reserve estimates are updated at least annually using geological and reserve data, as well as production performance data. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates, while decreases in recoverable economic volumes generally increase per unit depletion rates. A decline in proved reserves may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimate may impact the outcome of our assessment of oil and natural gas producing properties for impairment. We cannot predict what reserve revisions may be required in future periods.

We believe the estimate of oil and natural gas reserves is a critical accounting estimate because we must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the timing of development expenditures. Future results of operations for any period could be materially affected by changes in our assumptions. Significant changes in these estimates could result in a change to our estimated reserves, which could lead to a material change to our production depletion expense.

Derivative Financial Instruments. Our commodity derivative financial instruments are used to reduce the impact of natural gas and oil price fluctuations. We record our derivative instrument in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized currently in earnings as we have not elected hedge accounting for any of our derivative positions. Significant changes to the market value of derivative instruments due to the volatility of oil and natural gas prices can have an impact on our financial condition and results of operations.

Contingencies and Insurance Accounting. A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. Although we are insured against various risks to the extent we believe is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings.

Environmental costs for remediation are accrued when environmental remediation efforts are probable and the costs can be reasonably estimated. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals.

An insurance receivable is recognized when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between the insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment.

We believe contingencies and insurance accounting is a critical accounting estimate because we must assess the probability of the loss related to the contingency and the expected amount that is covered by insurance.

Income Tax. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (2) operating loss and tax credit carryforwards.

In assessing the carrying value of our net deferred tax assets, we consider the realizability of our deferred tax assets each reporting period. The realization of any deferred tax asset is dependent upon the generation of future taxable income sufficient to demonstrate our ability to utilize the deferred tax asset in the period in which the temporary differences become deductible or in a future period prior to expiration. We considered all available evidence, including cumulative historical losses (defined as pre-tax earnings as adjusted for permanent tax adjustment), scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretation of tax laws and the resolution of any tax audits could significantly impact the amounts provided for income taxes in our Consolidated Financial Statements. Any increase in the valuation allowance would increase our income tax expense in the Consolidated Statements of Operations.

We believe accounting for income taxes is a critical accounting estimate because the policies discussed above in assessing the carrying value of our net deferred tax assets require estimates and judgements about the impact of future events on our projected taxable income, the results of which can have a material impact on our Consolidated Financial Statements.

In future periods, we may demonstrate cumulative historical losses for the previous three fiscal years, which could significantly impact our need for a valuation allowance. Any increase in the valuation allowance would increase our income tax expense in the Consolidated Statements of Operations.

Revenue Payables in Suspense

In the normal course of business, we undertake efforts to research and resolve the disputes, legal reasons or uncertainties causing revenues of owners of mineral interests in our leases to go into suspense. As resolutions occur, obligations related to revenue payables in suspense are released. For the year ended December 31, 2024, we released $8.4 million of net revenues in suspense as a result of these efforts. The following table presents the impact of releases of revenue payables in suspense to our statements of operations for the year ended December 31, 2024:

	For the Year Ended December 31, 2024
	(In thousands)
Oil and natural gas sales	$ 4,023
Other revenues	4,829
Severance tax and other deducts	(433)
Total net revenue	$ 8,419
Production volumes:	
Oil (MBbls)	33
NGLs (MBbls)	31
Natural gas (MMcf)	441
Total (MBoe)	138
Total (MBoe/d)	0.38

Results of Operations

The results of operations for the years ended December 31, 2024 and 2023 have been derived from our Consolidated Financial Statements. The comparability of the results of operations among the periods presented below is impacted by the suspension of operations at our Beta properties for the first half of 2023.

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated.

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
	($ In thousands)	
Oil and natural gas sales	$ 282,992	$ 288,271
Other revenues	11,689	19,325
Lease operating expense	142,950	138,361
Gathering, processing and transportation	18,427	20,808
Taxes other than income	20,895	22,574
Depreciation, depletion and amortization	32,586	28,004
General and administrative expense	35,895	32,984
Loss (gain) on commodity derivative instruments	2,047	(40,343)
Pipeline incident loss	3,859	19,981
Interest expense, net	14,599	17,719
Litigation settlement	—	84,875
Income tax (expense) benefit - current	(232)	(4,817)
Income tax (expense) benefit - deferred	(2,196)	253,796
Net income (loss)	12,946	392,750
Oil and natural gas revenues:		
Oil sales	$ 220,380	$ 205,663
NGL sales	26,789	29,432
Natural gas sales	35,823	53,176
Total oil and natural gas revenues	$ 282,992	$ 288,271
Production volumes:		
Oil (MBbls)	3,060	2,773
NGLs (MBbls)	1,278	1,323
Natural gas (MMcf)	16,836	20,297
Total (MBoe)	7,144	7,479
Average net production (MBoe/d)	19.5	20.5
Average realized sales price (excluding commodity derivatives):		
Oil (per Bbl)	$ 72.01	$ 74.17
NGL (per Bbl)	20.96	22.24
Natural gas (per Mcf)	2.13	2.62
Total (per Boe)	$ 39.61	$ 38.54
Average unit costs per Boe:		
Lease operating expense	$ 20.01	$ 18.50
Gathering, processing and transportation	2.58	2.78
Taxes other than income	2.92	3.02
General and administrative expense	5.02	4.41
Depletion, depreciation and amortization	4.56	3.74

For the year ended December 31, 2024 compared to the year ended December 31, 2023

Net income of $12.9 million and $392.8 million was recorded for the year ended December 31, 2024 and 2023, respectively.

Oil, natural gas and NGL revenues were $283.0 million and $288.3 million for the year ended December 31, 2024 and 2023, respectively. Average net production volumes were approximately 19.5 MBoe/d and 20.5 MBoe/d for the year ended December 31, 2024 and 2023, respectively. The average realized sales price was $39.61 per Boe and $38.54 per Boe for the year ended December 31, 2024 and 2023, respectively. The increase in the average realized sales price was driven by more oil sales in 2024 due to Beta being online for the full year in 2024 compared to nine months in 2023. Net sales for Beta were $84.8 million for the year ended December 31, 2024 compared to $51.1 million for the year ended December 31, 2023.

Other revenues were $11.7 million and $19.3 million for the year ended December 31, 2024 and 2023, respectively. For the year ended December 31, 2024, other revenues consisted of iodine sales of $2.4 million, service revenues of $3.1 million with respect to our wholly owned subsidiary, Magnify Energy Services ("Magnify"), and interest income of $0.9 million earned on our sinking fund escrow accounts. Additionally, for the year ended December 31, 2024, we recorded a revenue suspense release of $4.8 million. For the year ended December 31, 2023, other revenues were primarily related to our receipt of LOPI insurance proceeds of $17.9 million, Magnify service revenue of $0.6 million and iodine sales of $0.2 million.

Lease operating expense was $143.0 million and $138.4 million for the year ended December 31, 2024 and 2023, respectively. The change in lease operating expense was primarily driven by higher base lease operating costs due to Beta being online for a full year in 2024 compared to nine months for 2023, offset by a credit received for transportation costs. On a per Boe basis, lease operating expense was $20.01 and $18.50 for the year ended December 31, 2024 and 2023, respectively. The change in lease operating expense on a per Boe basis was mainly due to an additional three months of costs associated with Beta being online for the full year in 2024 compared to nine months in 2023.

Gathering, processing and transportation expenses were $18.4 million and $20.8 million for the year ended December 31, 2024 and 2023, respectively. On a per Boe basis, gathering, processing and transportation expenses were $2.58 and $2.78 for the year ended December 31, 2024 and 2023, respectively. The decrease in gathering, processing and transportation expense was primarily driven by the expiration of the minimum volume commitment fee in Oklahoma (June 2023) and lower volumes.

Taxes other than income were $20.9 million and $22.6 million for the year ended December 31, 2024 and 2023, respectively. On a per Boe basis, taxes other than income were $2.92 and $3.02 for the year ended December 31, 2024 and 2023, respectively. The change in taxes other than income is due to a decrease of $1.6 million in production tax and a decrease in ad valorem tax of $1.3 million, partially offset by an increase in emission charges of $1.2 million.

DD&A expense was $32.6 million and $28.0 million for the year ended December 31, 2024 and 2023, respectively. The change in DD&A expense was primarily driven by the restart of production at Beta.

General and administrative expense was $35.9 million and $33.0 million for the year ended December 31, 2024 and 2023, respectively. The change in general and administrative expense is primarily related to (i) an increase of $1.5 million in stock compensation expense; (ii) an increase of $1.5 million in legal expense related to cost incurred with acquisitions and divestiture activities; and (iii) an increase of $0.4 million in office lease expense related to the early termination of our Oklahoma office lease partially offset by (i) a decrease of $0.3 million in salaries and other payroll benefits, and (ii) a decrease of $0.2 million in professional services.

Net loss (gain) on commodity derivative instruments for the year ended December 31, 2024 was a loss of $2.0 million which consisted of a $20.5 million decrease in the fair value of open positions, partially offset by a $0.8 million of cash settlements received on terminated derivative instruments and $17.6 million in cash settlements received on expired positions. Net gains on commodity derivative instruments of $40.3 million were recognized for the year ended December 31, 2023, consisting of a $47.9 million increase in the fair value of open positions and $0.7 million of cash settlements received on terminated derivative instruments, partially offset by $8.3 million in cash settlements paid on expired positions.

Given the volatility of commodity prices, it is not possible to predict future reported unrealized mark-to-market net gains or losses and the actual net gains or losses that will ultimately be realized upon settlement of the hedge positions in future years. If commodity prices at settlement are lower than the prices of the hedge positions, the hedges are expected to mitigate the otherwise negative effect on earnings of lower oil, natural gas and NGL prices. However, if commodity prices at settlement are higher than the prices of the hedge positions, the hedges are expected to dampen the otherwise positive effect on earnings of higher oil, natural gas and NGL prices and will, in this context, be viewed as having resulted in an opportunity cost.

Pipeline incident loss was $3.9 million and $20.0 million for the year ended December 31, 2024 and 2023. The $3.9 million reflects certain legal defense, loss load and regulatory costs associated with the Incident that are not expected to be recovered under an insurance policy. See Note 17 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Interest expense, net was $14.6 million and $17.7 million for the year ended December 31, 2024 and 2023, respectively. The change resulted from lower outstanding borrowings and amortization and write-off of deferred issuance costs.

Average outstanding borrowings under our Revolving Credit Facility were $120.9 million and $138.9 million for the year ended December 31, 2024 and 2023, respectively.

Litigation settlement was not recorded for the year ended December 31, 2024 and litigation settlement of $84.9 million was recorded for the year ended December 31, 2023, related to the settlement with the shipping companies and the containerships whose anchors struck the Company's pipeline. See additional information discussed in Note 17 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Current income tax (expense) benefit was ($0.2) million and ($4.8) million for the year ended December 31, 2024 and 2023, respectively. See additional information discussed in Note 19 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Deferred income tax benefit (expense) was ($2.2) million and $253.8 million for the year ended December 31, 2024 and 2023, respectively. Starting in the first quarter of 2023, we achieved three years of cumulative book income, which allowed the release of the valuation allowance. See additional information discussed in Note 19 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

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

Information related to the comparison of our discussion of the results of operations for the year ended December 31, 2023, compared to the year ended December 31, 2022, is included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the year ended December 31, 2023 ("2023 Form 10-K") filed with the SEC and is incorporated by reference into this Annual Report.

Non-GAAP Financial Measures

We include in this report the non-GAAP financial measures for Adjusted Net Income (Loss) and Adjusted EBITDA and provide our reconciliation of net income (loss) to Adjusted Net Income (Loss) and a reconciliation of net cash flow from operating activities to Adjusted EBITDA, our most directly comparable financial measure calculated and presented in accordance with GAAP.

We define Adjusted Net Income (Loss) as net income (loss) adjusted for unrealized loss (gain) on commodity derivative instruments, acquisition & divestiture related expenses, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our federal statutory tax rate. Adjusted Net Income (Loss) excludes the impact of unusual and infrequent items affecting earnings that can vary widely and unpredictably, including unrealized derivative gains and losses. This measure is not meant to disassociate these items from management's performance but rather is intended to provide helpful information to investors interested in comparing our performance between periods. Adjusted Net Income (Loss) is not considered to be an alternative to net income (loss) reported in accordance with GAAP.

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. We define Adjusted EBITDA as net income (loss):

Plus:

- Interest expense, including gains or losses on interest rate derivative contracts;
- Income tax expense;
- DD&A;
- Impairment of goodwill and long-lived assets (including oil and natural gas properties);
- Accretion of asset retirement obligations ("AROs");
- Loss on commodity derivative instruments;

- Cash settlements received on expired commodity derivative instruments;
- Losses on sale of assets and other, net;
- Share-based compensation expenses;
- Exploration costs;
- Acquisition and divestiture related expenses;
- Amortization of gain associated with terminated commodity derivatives;
- Severance payments;
- Bad debt expense; and
- Other non-routine items that we deem appropriate.

Less:

- Interest income;
- Income tax benefit;
- Gain on expired commodity derivative instruments;
- Cash settlements paid on expired commodity derivative instruments;
- Gains on sale of assets and other, net; and
- Other non-routine items that we deem appropriate.

We are required to comply with certain Adjusted EBITDA-related metrics under our Revolving Credit Facility.

We believe that Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure.

Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. 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 structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

In addition, management uses Adjusted EBITDA to evaluate actual cash flow, develop existing reserves or acquire additional oil and natural gas properties.

The following tables present a reconciliation of the Company's net income (loss) and cash flows operating activities to Adjusted EBITDA, our most directly comparable GAAP financial measures, for each of the periods indicated.

Reconciliation of Net Income (Loss) to Adjusted Net Income (Loss)

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Adjusted net income (loss) reconciliation:		
Net (loss) income	$ 12,946	$ 392,750
Unrealized loss (gains) on commodity derivative instruments	20,457	(47,958)
Acquisition and divestiture related expenses	1,633	219
Non-recurring costs:		
Litigation Settlement (1)	—	(84,875)
Income tax expense (benefit) - deferred (2)	2,196	(253,796)
Gain on sale of properties	(1,367)	—
Tax effect of adjustments (3)	(56)	17,778
Adjusted net income (loss)	$ 35,809	$ 24,118

(1) In 2023, non-recurring costs included a litigation settlement with the shipping companies and the containerships whose anchors struck the Company's pipeline.
(2) In 2023, we achieved three years of cumulative book income which resulted in the release of our valuation allowance of $284.9 million.
(3) The federal statutory rates were utilized for all periods presented.

Reconciliation of Net Income (Loss) to Adjusted EBITDA

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Net income (loss)	$ 12,946	$ 392,750
Interest expense, net	14,599	17,719
Income tax expense (benefit) - current	232	4,817
Income tax expense (benefit) - deferred	2,196	(253,796)
DD&A	32,586	28,004
Accretion of AROs	8,438	7,951
Losses (gains) on commodity derivative instruments	2,047	(40,343)
Cash settlements (paid) received on expired commodity derivative instruments	17,617	(8,273)
Amortization of gain associated with terminated commodity derivatives	159	658
Pipeline incident loss	3,859	19,981
(Gain) loss on sale of properties	(1,367)	—
Share-based compensation expense	6,799	5,280
Acquisition and divestiture related expenses	1,633	219
Litigation settlement	—	(84,875)
Loss on settlement of AROs	470	1,003
Exploration costs	61	57
Bad debt expense	80	98
LOPI - timing difference	—	(4,636)
Other	686	1,418
Adjusted EBITDA(1)	$ 103,041	$ 88,032

(1) Adjusted EBITDA includes a revenue suspense release of $8.4 million for the year ended December 31, 2024. See "Revenue Payables in Suspense" discussion noted above for additional information.

Reconciliation of Net Cash from Operating Activities to Adjusted EBITDA

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Net cash provided by operating activities	$ 51,293	$ 141,590
Changes in working capital	32,272	(8,517)
Interest expense, net	14,599	17,719
Pipeline incident loss	3,859	19,981
(Gain) loss on sale of property	(1,367)	—
Litigation settlement	—	(84,875)
Income tax expense (benefit) - current	232	4,817
Acquisition and divestiture related expenses	1,633	219
Plugging and abandonment cost	1,640	2,239
Amortization and write-off of deferred financing fees	(1,233)	(1,980)
Exploration costs	61	57
Cash settlements paid (received) on terminated derivatives	(793)	(658)
Amortization of gain associated with terminated commodity derivatives	159	658
LOPI - timing difference	—	(4,636)
Other	686	1,418
Adjusted EBITDA[1]	$ 103,041	$ 88,032

(1) Adjusted EBITDA includes a revenue suspense release of $8.4 million for the year ended December 31, 2024. See “Revenue Payables in Suspense” discussion noted above for additional information.

Liquidity and Capital Resources

Overview. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our primary sources of liquidity and capital resources have historically been cash flows generated by operating activities, borrowings under our Revolving Credit Facility, and equity and debt capital markets. However, future cash flows are subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production, and significant additional capital expenditures will be required to more fully develop our properties. We cannot assure you that operations and other needed capital will be available on acceptable terms, or at all. We anticipate funding our 2025 capital program from internally generated cash flow but retain the flexibility to utilize borrowings under debt facilities available to us, and/or to access the debt and equity capital markets. As we pursue reserve and production growth, we plan to monitor which capital resources, including equity and debt financings, are available to us to meet our future financial obligations, planned capital expenditure activities and liquidity requirements.

Prior to the closing of the Mergers, based on our current oil and natural gas price expectations, we believe our cash flows provided by operating activities and availability under our Revolving Credit Facility will provide us with the financial flexibility necessary to meet our cash requirements, including normal operating needs, and to pursue our currently planned 2025 development activities. In connection with the Mergers, we expect to refinance a substantial portion of our outstanding debt and approximately $133 million in principal amount of the Acquired Companies’ outstanding debt. We believe that existing cash and cash equivalents, any positive cash flows from operations and available borrowings under our Revolving Credit Facility following such refinancings made in connection with the Mergers will be sufficient to support working capital, capital expenditures and other cash requirements for at least the next 12 months and, based on our current expectations, for the foreseeable future thereafter.

There is no guarantee that we will be able to execute a refinancing in connection with the Mergers on favorable terms or at all. If we are unable to complete a sufficient refinancing at all, we may not be able to complete the Mergers. In certain circumstances (described in further detail above in "— Recent Developments — Merger with Juniper Capital"), upon termination of the Merger Agreement, we will be required to pay the Amplify Termination Fee, which could adversely affect our financial condition. For a discussion of risks associated with our liquidity and capital resources related to the Mergers, see "Item 1A. Risk Factors — Risks Related to the Mergers — We expect to refinance substantial indebtedness of the Acquired Companies in connection with the Mergers, which combined with our current debt may limit our financial flexibility and adversely affect our financial results" and "Item 1A. Risk Factors — Risks Related to the Mergers — The Merger Agreement limits our ability to pursue alternatives to the Mergers and may discourage a potential competing acquirer of Amplify Energy, including the payment by Amplify Energy of a Termination Fee." If the Mergers are not completed, based on our current oil and natural gas price expectations, we believe our cash flows provided by operating activities and availability under our Revolving Credit Facility will provide us with the financial flexibility necessary to meet our cash requirements, including normal operating needs, and to pursue our currently planned 2025 development activities. Further, if the Mergers are not completed, we believe that existing cash and cash equivalents, any positive cash flows from operations and available borrowings under our Revolving Credit Facility will be sufficient to support working capital, capital expenditures and other cash requirements for at least the next 12 months and, based on our current expectations, for the foreseeable future thereafter.

Capital Markets. On January 15, 2024, we entered into the Merger Agreement, pursuant to which we agreed to issue 26,729,315 shares of our Common Stock to Juniper as consideration for all of the outstanding equity of the Acquired Companies. However, such issuance remains subject to stockholder approval. For additional information, see "—Recent Developments." In connection with the Mergers, we may also evaluate additional capital markets transactions in order to refinance all or a portion of the Acquired Companies' outstanding indebtedness.

Hedging. Commodity hedging has been and remains an important part of our strategy to reduce cash flow volatility. Our hedging activities are intended to support oil, NGL and natural gas prices at targeted levels and to manage our exposure to commodity price fluctuations. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 50%−75% of our estimated production from total proved developed producing reserves over a one-to-three-year period at any given point of time. We may, however, from time to time, hedge more or less than this approximate amount. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes when circumstances suggest that it is prudent to do so. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices. We sell our oil and natural gas to a variety of purchasers. Non-performance by a customer could also result in losses.

Capital Expenditures. Our total capital expenditures were approximately $70.6 million for the year ended December 31, 2024, which were primarily related to the development program at Beta, capital workovers and facilities upgrades at Beta and in Oklahoma and non-operated drilling and completion activities in East Texas and the Eagle Ford.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable as well as the classification of our debt outstanding. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

As of December 31, 2024, we had a working capital deficit (excluding commodity derivatives) of $2.7 million primarily as the result of (i) an accrued liabilities balance of $43.4 million, (ii) an accounts payable balance of $13.2 million, and (iii) a revenue payable balance of $11.5 million, less (i) an accounts receivable balance of $39.7 million and (ii) prepaid expenses and other current assets balance of $25.7 million.

Debt Agreements

Revolving Credit Facility. On July 31, 2023, OLLC, as borrower, entered into the Revolving Credit Facility. The Revolving Credit Facility is a replacement in full of the prior revolving credit facility, by and among OLLC, Amplify Acquisitionco LLC, a Delaware limited liability company, the guarantors party thereto, the lenders party thereto and KeyBank National Association, as administrative agent (as amended, the "Prior Revolving Credit Facility"). At December 31, 2024, the aggregate principal amount of loans outstanding under the Revolving Credit Facility was $127.0 million.

On October 25, 2024, we entered into the Credit Agreement Amendment, which among other things, (i) reduced the borrowing base under the Revolving Credit Facility from $150.0 million to $145.0 million, (ii) increased the aggregate elected commitments under the Revolving Credit Facility from $135.0 million to $145.0 million and (iii) amended certain interest rates applicable to loans under the Revolving Credit Facility.

As of December 31, 2024, we had approximately $18.0 million of available borrowings under our Revolving Credit Facility.

As of December 31, 2024, we were in compliance with all the financial (current ratio and total leverage ratio) and non-financial covenants associated with our Revolving Credit Facility.

For additional information regarding our Revolving Credit Facility, see Note 9 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report for additional information.

Material Cash Requirements

Contractual commitments. We have contractual commitments under our debt agreements, including interest payments and principal payments. See Note 9 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report for additional information.

Lease Obligations. We have operating leases for office and warehouse spaces, office equipment, compressors and surface rentals related to our business obligations. As of December 31, 2024, our future commitments under these contracts were $2.1 million in 2025, $1.4 million in 2026, $1.0 million in 2027, $0.7 million in 2028 and $1.1 million thereafter. See Note 13 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report for additional information.

Sinking fund payments. We have a funding requirement to fund a trust account to comply with supplemental regulatory bonding requirements related to our decommissioning obligations for our Beta production facilities. As of December 31, 2024, our future commitments under this agreement were $9.0 million per year for years 2025 through 2033. See Note 18 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report for additional information.

Fines. We currently have a payment plan to pay our federal fines over a period of three years with one year remaining in such plan. We are scheduled to pay $1.1 million in September 2025.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated. The cash flows for the years ended December 31, 2024 and 2023, have been derived from our Consolidated Financial Statements. For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under "Item 8. Financial Statements and Supplementary Data" contained herein.

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Net cash provided by operating activities	$ 51,293	$ 141,590
Net cash used in investing activities	(82,034)	(38,602)
Net cash used in financing activities	9,995	(82,242)

For the year ended December 31, 2024 compared to the year ended December 31, 2023

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes, operating costs and the settlement received related to the Incident. Net cash provided by operating activities was $51.3 million and $141.6 million for the year ended December 31, 2024 and 2023, respectively. Production volumes decreased to 19.5 MBoe/d in 2024 from 20.5 MBoe/d in 2023, and the average realized sales price increased to $39.61 per Boe in 2024 from $38.54 per Boe in 2023. The increase in average realized sales price was driven by more oil sales in 2024 due to Beta being online for a full year in 2024 compared to nine months in 2023. For the year ended December 31, 2023, we received $84.9 million in connection with the settlement between the Company and the vessels that struck and damaged the pipeline and their respective owners and operators.

Net cash provided by operating activities for the year ended December 31, 2024 included $17.6 million of cash received on expired derivative instruments and $0.8 million of cash received on terminated derivative instruments compared to $8.3 million of cash paid on expired derivative instruments and $0.7 million of cash received on terminated derivatives instruments for the year ended December 31, 2023. For the year ended December 31, 2024, we had a net loss on commodity derivative instruments of $2.0 million compared to net gains of $40.3 million for the year ended December 31, 2023.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2024 was $82.0 million, of which $72.2 million was used for additions to oil and natural gas properties and $1.1 million used for additions to other property and equipment. Net cash used in investing activities for the year ended December 31, 2023, was $38.6 million, of which $30.7 million was used for additions to oil and natural gas properties.

For the year ended December 31, 2024, in East Texas we sold some undeveloped acreage recognizing a gain of $1.4 million. For the year ended December 31, 2023, in East Texas, we sold a small working interest in certain acreage for $1.2 million and an override royalty interest.

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with our offshore Beta properties. Additions to restricted investments were $10.1 million for the year ended December 31, 2024 compared to $8.6 million for the year ended December 31, 2023.

Financing Activities. We had net borrowings of $12.0 million for the year ended December 31, 2024, compared to net repayments of $75.0 million for the year ended December 31, 2023, under our Revolving Credit Facility.

For the year ended December 31, 2023, we paid $4.8 million in deferred financing costs under the Revolving Credit Facility.

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

Information related to the comparison of our discussion of the cash flows for the year ended December 31, 2023 compared to the year ended December 31, 2022, is included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" of our 2023 Form 10-K filed with the SEC and is incorporated by reference into this Annual Report.

Capital Requirements

See "— Outlook" for additional information regarding our capital spending program for 2025.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm, begin on page F-1 of this Annual Report and are incorporated herein by reference.

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.

As required by Rules 13a-15(b) and 15d-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the principal executive officer and principal financial officer of the Company, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of the Company, as appropriate, to allow timely decisions regarding required disclosure, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon this evaluation, the principal executive officer and principal financial officer of the Company have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2024.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting, no matter how well designed, has inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Under the supervision and with the participation of the Company's management, including the principal executive officer and principal financial officer of the Company, the Company assessed the effectiveness of its internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this assessment, the Company's management, including its principal executive and financial officers, concluded that the Company's internal control over financial reporting was effective as of December 31, 2024, based on the criteria set forth under the COSO Framework.

Deloitte & Touche LLP, the independent registered public accounting firm who audited the Company's Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" in this Annual Report, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2024. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2024, is contained herein under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Controls Over Financial Reporting

No changes in our internal control over financial reporting occurred during the quarter ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits 31.1 and 31.2 to this Annual Report.

Report of Independent Registered Public Accounting Firm

To the shareholders and the Board of Directors of Amplify Energy Corp.

Opinion on Internal Control Over Financial Reporting

We have audited the internal control over financial reporting of Amplify Energy Corp. and subsidiaries (the "Company") as of December 31, 2024, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2024, of the Company and our report dated March 5, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 5, 2025

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement relating to the 2025 Annual Meeting of Stockholders of Amplify Energy Corp. (the "Proxy Statement") that is expected to be held in the second quarter of 2025.

The Company has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") which applies to employees, officers and directors of the Company. The Code of Ethics can be found on the Company's website located at https://www.amplifyenergy.com/investor-relations/corporate-governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the Proxy Statement.

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

The information required by this item is incorporated herein by reference to the Proxy Statement.

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

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) *Financial Statements*

Our Consolidated Financial Statements are included under Part II, "Item 8. Financial Statements and Supplementary Data" of the Annual Report. For a listing of these statements and accompanying footnotes, see *"Index to Financial Statements"* on page F-1 of this Annual Report.

(a)(2) *Financial Statement Schedules*

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

(a)(3) *Exhibits*

The exhibits listed on the Exhibit Index below are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

Exhibit Index

Exhibit Number		Description
2.1	—	Agreement and Plan of Merger, dated May 5, 2019, by and among Amplify Energy Corp., Midstates Petroleum Company, Inc. and Midstates Holdings, Inc. (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-35364) filed on May 6, 2019).
3.1	—	Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
3.2	—	Certificate of Amendment to the Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc., dated August 6, 2019 (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
3.3	—	Third Amended and Restated Bylaws of Amplify Energy Corp. (incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 15, 2021).
4.1	—	Description of the Company's Capital Stock Registered Under Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.3 to Annual Report on Form 10-K (File No. 0001-35512) filed on March 5, 2020).
10.1	—	Amended and Restated Credit Agreement dated July 31, 2023, among Amplify Energy Operating LLC, as borrower, Amplify Acquisitionco LLC, as parent, the lenders party thereto and KeyBank National Association, as administrative agent and a letter of credit issuer (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 1, 2023).
10.2	—	Borrowing Base Redetermination, Commitment Increase and First Amendment to Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on October 25, 2024).
10.3#	—	Amplify Energy Corp. Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-8 (File No. 333-257071) filed on June 14, 2021).
10.4#	—	Amplify Energy Corp. 2024 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-8 (File No. 333-279868) filed on May 31, 2024).

Exhibit Number		Description
10.5#	—	Form of 2024 TRSU Award Agreement (incorporated by reference to Exhibit 10.18 to the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 7, 2024).
10.6#	—	Form of 2024 PRSU Award Agreement (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 7, 2024).
10.7#	—	Form of 2024 TRSU Award Agreement (2024 EIP) (incorporated by reference to Exhibit 10.2 to the Company's Quarter Report on Form 10-Q (File No.001-33512) filed on August 7, 2024).
10.8#	—	Form of 2024 PRSU Award Agreement (2024 EIP) (incorporated by reference to Exhibit 10.3 to the Company's Quarter Report on Form 10-Q (File No.001-33512) filed on August 7, 2024).
10.9*#	—	Form of 2025 TRSU Award Agreement.
10.10*#	—	Form of 2025 PRSU Award Agreement.
10.11#	—	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Eric Dulany (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.12#	—	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and James Frew (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.13#	—	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Daniel Furbee (incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.14#	—	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Tony Lopez (incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.15#	—	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Eric Willis (incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.16#	—	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Martyn Willsher (incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.17	—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.16 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
19.1*	—	Insider Trading Policy and Other Restrictions on Trading.
21.1*	—	List of Subsidiaries of Amplify Energy Corp.
23.1*	—	Consent of Cawley, Gillespie and Associates, Inc.
23.2*	—	Consent of Deloitte & Touche LLP.
31.1*	—	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	—	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.

Exhibit Number		Description
32.1*	—	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1	—	Amplify Energy Corp. Clawback Policy (incorporated by reference to Exhibit 97.1 of the Company's Annual Report on Form 10-K (File No. 001-35512) filed on March 7, 2024).
99.1*	—	Report of Cawley, Gillespie and Associates, Inc.
101.INS*	—	Inline XBRL Instance Document
101.SCH*	—	Inline XBRL Schema Document
101.CAL*	—	Inline XBRL Calculation Linkbase Document
101.DEF*	—	Inline XBRL Definition Linkbase Document
101.LAB*	—	Inline XBRL Labels Linkbase Document
101.PRE*	—	Inline XBRL Presentation Linkbase Document
104*	—	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Filed or furnished as an exhibit to this Annual Report on Form 10-K.

\# Management contract or compensatory plan or arrangement.

\## Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

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.

Amplify Energy Corp.
(Registrant)

Date: March 5, 2025

By: /s/ James Frew
Name: James Frew
Title: Senior Vice President and Chief Financial 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 their capacities and on the dates indicated.

Name	Title (Position with Amplify Energy Corp.)	Date
/s/ Martyn Willsher Martyn Willsher	President and Chief Executive Officer (Principal Executive Officer)	March 5, 2025
/s/ James Frew James Frew	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 5, 2025
/s/ Eric Dulany Eric Dulany	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 5, 2025
/s/ Christopher W. Hamm Christopher W. Hamm	Chairman and Director	March 5, 2025
/s/ Deborah Adams Deborah Adams	Director	March 5, 2025
/s/ James E. Craddock James E. Craddock	Director	March 5, 2025
/s/ Patrice Douglas Patrice Douglas	Director	March 5, 2025
/s/ Vidisha Prasad Vidisha Prasad	Director	March 5, 2025
/s/ Todd R. Snyder Todd R. Snyder	Director	March 5, 2025

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AMPLIFY ENERGY CORP.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Amplify Energy Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Amplify Energy Corp. and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of operations, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 5, 2025, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matter

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

Oil and Natural Gas Properties, Depletion – Oil and Natural Gas Reserve Quantities as used in the calculation of DD&A— Refer to Note 2 to the financial statements.

Critical Audit Matter Description

The Company's proved oil and natural gas properties are depleted using the units-of -production method based on proved oil and natural gas reserves related to the associated field. The development of the Company's oil and natural gas reserve quantities require management to make significant estimates and assumptions. The Company engages an independent reservoir engineer, management's specialist, to estimate oil and natural gas quantities using generally accepted methods, calculation procedures and engineering data. Changes in assumptions or engineering data could have a significant impact on the amount of depletion expense. The depletion expense balance for the year ended December 31, 2024 was $30.6 million.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's proved oil and natural gas reserves, including management's estimates and assumptions related to the best estimate of future production and converting proved undeveloped reserves to producing oil and natural gas properties within five years, required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to oil and natural gas reserves included the following, among others:

- We tested the design and implementation and operating effectiveness of controls related to the Company's estimation of proved oil and natural gas reserve quantities.
- We evaluated the Company's best estimate of future production by:
    - Comparing the Company's best estimate of future production to historical production volumes.
    - Assessing the reasonableness of the production volume decline curves by comparing to historical decline curve estimates.
- We evaluated the reasonableness of management's estimates and assumptions related to converting proved undeveloped reserves to producing oil and natural gas properties within five years, by performing the following:
    - Comparing historical conversions of proved undeveloped reserves into proved developed reserves to management's forecasts of conversions.
    - Comparing management's forecasts to the Company's drilling plan and the availability of capital relative to the drilling plan.
    - Evaluating whether the forecasted date of development for the proved undeveloped locations are within five years of their original booking date.
    - Reviewing the internal development plan approved by management and the Board of Directors.
- We evaluated the experience, qualifications and objectivity of management's expert, an independent reserve engineering firm.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 5, 2025

We have served as the Company's auditor since 2020.

AMPLIFY ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(In thousands, except outstanding shares)

	December 31, 2024	December 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	$ —	$ 20,746
Accounts receivable, net (see Note 14)	39,713	39,096
Short-term derivative instruments	6,385	17,669
Prepaid expenses and other current assets	25,679	20,672
Total current assets	71,777	98,183
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	942,981	873,478
Support equipment and facilities	150,511	149,069
Other	11,478	10,359
Accumulated depreciation, depletion and amortization	(718,752)	(686,165)
Property and equipment, net	386,218	346,741
Long-term derivative instruments	233	9,405
Restricted investments	29,993	19,935
Operating lease - long term right-of-use asset	4,540	5,756
Deferred tax asset	251,600	253,796
Other long-term assets	2,715	3,858
Total assets	$ 747,076	$ 737,674
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 13,231	$ 23,616
Revenues payable	11,494	21,944
Accrued liabilities (see Note 14)	43,413	50,871
Total current liabilities	68,138	96,431
Long-term debt (see Note 9)	127,000	115,000
Asset retirement obligations	129,700	122,001
Operating lease liability	3,683	5,090
Other long-term liabilities	9,643	8,116
Total liabilities	338,164	346,638
Commitments and contingencies (see Note 18)		
Stockholders' equity (deficit):		
Preferred stock, $0.01 par value: 50,000,000 shares authorized; no shares issued and outstanding at December 31, 2024 and December 31, 2023	—	—
Common Stock, $0.01 par value: 250,000,000 shares authorized; 39,795,138 and 39,147,205 shares issued and outstanding at December 31, 2024 and December 31, 2023, respectively	399	393
Additional paid-in capital	439,981	435,095
Accumulated deficit	(31,468)	(44,452)
Total stockholders' equity (deficit)	408,912	391,036
Total liabilities and equity	$ 747,076	$ 737,674

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Revenues:		
Oil and natural gas sales	$ 282,992	$ 288,271
Other revenues	11,689	19,325
Total revenues	294,681	307,596
Costs and expenses:		
Lease operating expense	142,950	138,361
Gathering, processing and transportation	18,427	20,808
Taxes other than income	20,895	22,574
Depreciation, depletion and amortization	32,586	28,004
General and administrative expense	35,895	32,984
Accretion of asset retirement obligations	8,438	7,951
Loss (gain) on commodity derivative instruments	2,047	(40,343)
Pipeline incident loss	3,859	19,981
(Gain) loss on sale of properties	(1,367)	—
Other, net	531	1,060
Total costs and expenses	264,261	231,380
Operating income (loss)	30,420	76,216
Other income (expense):		
Interest expense, net	(14,599)	(17,719)
Litigation settlement (See Note 17)	—	84,875
Other income (expense)	(447)	399
Total other income (expense)	(15,046)	67,555
Income (loss) before income taxes	15,374	143,771
Income tax (expense) benefit - current	(232)	(4,817)
Income tax (expense) benefit - deferred	(2,196)	253,796
Net income (loss)	12,946	392,750
Allocation of net income (loss) to:		
Net income (loss) available to common stockholders	12,324	375,151
Net income (loss) allocated to participating securities	622	17,599
Net income (loss) available to Amplify Energy Corp.	$ 12,946	$ 392,750
Earnings (loss) per share: (See Note 11)		
Basic and diluted earnings (loss) per share	$ 0.31	$ 9.63
Weighted average common shares outstanding:		
Basic and diluted	39,655	38,961

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Cash flows from operating activities:		
Net income (loss)	$ 12,946	$ 392,750
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	32,586	28,004
Loss (gain) on derivative instruments	2,047	(40,343)
Cash settlements (paid) received on expired derivative instruments	17,616	(8,273)
Cash settlements received (paid) on terminated derivative instruments	793	658
Deferred income tax expense (benefit)	2,196	(253,796)
Accretion of asset retirement obligations	8,438	7,951
Share-based compensation (see Note 12)	6,799	5,280
Settlement of asset retirement obligations	(1,170)	(1,236)
Amortization and write-off of deferred financing costs	1,233	1,980
Bad debt expense	80	98
Changes in operating assets and liabilities:		
Accounts receivable	(697)	41,262
Prepaid expenses and other assets	(7,561)	(482)
Payables and accrued liabilities	(24,013)	(31,501)
Other	—	(762)
Net cash provided by operating activities	51,293	141,590
Cash flows from investing activities:		
Additions to oil and gas properties	(72,226)	(30,667)
Additions to other property and equipment	(1,118)	(711)
Additions to restricted investments	(10,057)	(8,609)
Other	1,367	1,385
Net cash used in investing activities	(82,034)	(38,602)
Cash flows from financing activities:		
Advances on Revolving Credit Facility	117,000	125,000
Payments on Revolving Credit Facility	(105,000)	(200,000)
Deferred financing costs	(136)	(4,813)
Shares withheld for taxes	(1,869)	(2,429)
Net cash used in financing activities	9,995	(82,242)
Net change in cash and cash equivalents	(20,746)	20,746
Cash and cash equivalents, beginning of period	20,746	—
Cash and cash equivalents, end of period	$ —	$ 20,746

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands)

	Stockholders' Equity			
	Common Stock	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total
Balance at December 31, 2022	$ 386	$ 432,251	$ (437,202)	$ (4,565)
Net income (loss)	—	—	392,750	392,750
Share-based compensation expense	—	5,280	—	5,280
Shares withheld for taxes	—	(2,429)	—	(2,429)
Other	7	(7)	—	—
Balance at December 31, 2023	393	435,095	(44,452)	391,036
Net income (loss)	—	—	12,946	12,946
Share-based compensation expense	—	6,761	38	6,799
Shares withheld for taxes	—	(1,869)	—	(1,869)
Other	6	(6)	—	—
Balance at December 31, 2024	$ 399	$ 439,981	$ (31,468)	$ 408,912

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Basis of Presentation

General

Amplify Energy Corp. ("Amplify Energy" or the "Company"), is a publicly traded Delaware corporation, in which our common stock, par value of $0.01 per share ("Common Stock"), is listed on the New York Stock Exchange (the "NYSE"), under the symbol "AMPY."

The Company operates in one reportable segment engaged in the acquisition, development, exploitation and production of oil and natural gas properties. The Company's management evaluates performance based on one reportable business segment as there are not different economic environments within the operation of our oil and natural gas properties. The Company assets consist primarily of producing oil and natural gas properties located in Oklahoma, the Rockies ("Bairoil"), federal waters offshore Southern California ("Beta"), East Texas/North Louisiana and the Eagle Ford (non-op). Most of the Company's oil and natural gas properties are located in large, mature oil and natural gas reservoirs. The Company's properties consist primarily of operated and non-operated working interests in producing and undeveloped leasehold acreage and working interests in identified producing wells.

Basis of Presentation

Material intercompany transactions and balances have been eliminated in preparation of the Company's Consolidated Financial Statements. The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

Amounts in the prior years consolidated financial statements are reclassified whenever necessary to conform to the current year's presentation. Reclassification adjustments had no impact on prior year net income (loss) or shareholders' equity.

Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of Consolidated Financial Statements in conformity with 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 Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion and amortization of oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity compensation; and asset retirement obligations.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Beta oil and gas properties. These restricted investments consist of money market deposit accounts which are held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure.

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, individuals and others who own interests in the properties operated by the Company. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. An allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. The Company recorded $1.7 million and $1.6 million, respectively, as an allowance for doubtful accounts at December 31, 2024 and 2023.

If the Company was to lose any one of its customers, the loss could temporarily delay the production and the sale of oil and natural gas in the related producing region. If it were to lose any single customer, the Company believes that a substitute customer to purchase the impacted production volumes could be identified.

The following individual customers each accounted for 10% or more of total reported revenues for the period indicated:

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Major customers:		
Phillips 66	33 %	17 %
HF Sinclair Corporation (formerly: Sinclair Oil & Gas Company)	25 %	24 %
Southwest Energy LP	10 %	13 %

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. The costs of exploratory wells are initially capitalized, pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, seismic costs and delay rental payments attributable to unproved locations are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

Support equipment and facilities, which are primarily related to our Bairoil and Beta assets, are depreciated using the straight-line method generally based on estimated useful lives of twelve to twenty-four years.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

There were no material capitalized exploratory drilling costs pending evaluation at December 31, 2024 and 2023.

Oil and Natural Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the Consolidated Financial Statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board ("FASB"). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. The development of the Company's oil and natural gas reserve quantities requires management to make significant estimates and assumptions related to the intent and ability to complete undeveloped proved reserves within a five-year development period, as prescribed by SEC guidelines. Additionally, none of the Company's PUDs are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUD as prescribed by the SEC guidelines. PUDs are converted from undeveloped to developed as applicable wells begin production. We engaged Cawley, Gillespie and Associates, Inc. ("CG&A"), our independent reserve engineers, to prepare our reserves estimates for all of the Company's estimated proved reserves at December 31, 2024 and 2023.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates, while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment are stated at historical cost and is comprised primarily of vehicles, furniture, fixtures, office build-out cost and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to seven years.

Restricted Investments

Restricted investment accounts fund certain long-term asset retirement obligations and collateralize certain regulatory bonds associated with the Beta oil and gas properties. These investments are classified as held-to-maturity and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense, net in the Consolidated Statements of Operations. These restricted investments may consist of money market deposit accounts and U.S. Government securities. See Note 8 and Note 18 for additional information.

Debt Issuance Costs

Debt issuance costs are recorded in prepaid expenses and other current assets line item on the balance sheet and amortized over the term of the associated debt using the straight-line method, which generally approximates the effective yield method. Amortization expense, including write-off of debt issuance costs, for the years ended December 31, 2024 and 2023 was approximately $1.2 million and $2.0 million, respectively, as reflected in interest expense, net in the Consolidated Statements of Operations.

Impairments

Oil and natural gas properties including supporting equipment and facilities are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. This may be due to a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future net cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted net future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of future proved and probable reserves, commodity prices, production costs, and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. No impairment expense related to its proved properties was recorded for the years ended December 31, 2024 and 2023.

Unproved oil and natural gas properties are reviewed for impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, the expense is reported in impairment expense.

No impairment expense related to the Company's unproved properties was recorded for the years ended December 31, 2024 and 2023.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized in net income (loss) to the extent the actual costs differ from the recorded liability. See Note 7 for further discussion of asset retirement obligations.

Revenue Recognition

The Company revenue is primarily derived from the sale of oil and natural gas production, as well as the sale of NGLs that are extracted from natural gas during processing. Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. The performance obligation is the delivery of the commodity at a point in time. Prices for oil, natural gas and NGLs sales are negotiated based on index or spot price, distance from the well to pipeline, commodity quality and prevailing supply and demand conditions. To the extent actual quantities and values of oil, NGLs and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties must be estimated.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, collars and puts) are used to reduce the impact of natural gas and oil price fluctuations. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

The Company is a corporation subject to federal and certain state income taxes.

The Company uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled.

In assessing the carrying value of the Company's net deferred tax assets, it considers the realizability of its deferred tax assets each reporting period. The realization of any deferred tax asset is dependent upon the generation of future taxable income sufficient to demonstrate its ability to utilize the deferred tax asset in the period in which the temporary differences become deductible or in a future period prior to expiration. The Company considers all available evidence, including cumulative historical losses (defined as pre-tax earnings as adjusted for permanent tax adjustment), scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies.

The Company recognizes a tax (expense) benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination by taxing authorities, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through effective settlement with a taxing authority. As of December 31, 2024, the Company has no uncertain tax positions.

Earnings (loss) Per Share

Basic and diluted earnings (loss) per share ("EPS") is determined by dividing net income (loss) available to the common stockholders by the weighted average number of outstanding shares during the period. Diluted earnings (loss) per common share is calculated under the two-class method and the treasury stock method by dividing net income (loss) available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See Note 11 for additional information.

Equity Compensation

The fair value of equity-classified awards (e.g., restricted common unit awards, restricted stock units or stock options) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., phantom units awards) are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. The Company currently has awards subject to performance criteria; such awards would vest when it is probable that the performance criteria will be met and the requisite service period has been met. Generally, no compensation expense is recognized for equity instruments that do not vest. See Note 12 for further information.

Lease Recognition

The FASB retained a dual model, requiring leases to be classified as either direct financing or operating leases. The classification will be based on criteria that are similar to the current lease accounting treatment. The Company is the lessee under various agreements for office space, warehouse, compressors, equipment, vehicles and surface rentals (right of use assets) that are currently accounted for as operating leases. See Note 13 for additional information regarding leases.

Loss of Production Income Insurance

The Company's insurance coverage includes loss of production income ("LOPI") insurance for our offshore properties. Proceeds from LOPI insurance claims are intended to partially offset the loss of revenue resulting from certain events that cause suspension of operations. When such event occurs, the Company files claims under its LOPI policy and recognizes LOPI in the period that insurers accept the claim and all uncertainty with respect to the receipt or amount of claim is resolved. The Company classifies LOPI within "Other revenues" in the Consolidated Statements of Operations.

For the year ended December 31, 2023, the Company recognized LOPI insurance payments of $17.9 million from our Beta properties due to the Incident (as defined below). The Company's LOPI insurance policy in effect at the time of the pipeline incident provided eighteen months of LOPI coverage. As such, the Company did not recognize any LOPI insurance payments for the year ended December 31, 2024. See Note 17 for additional information regarding the pipeline incident.

Insurance Coverage

The Company recognizes an insurance receivable when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between the insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment. See Note 17 for additional information regarding the pipeline incident.

New Accounting Pronouncements

Improvements to Income Tax Disclosure. In December 2023, the Federal Accounting Standards Board ("FASB") issued an accounting standard update which requires that companies disclose the nature and magnitude of factors contributing to the difference between their effective tax rate and the statutory tax rate. The update will require companies to disclose specific categories in the rate reconciliation and provide additional information about items that meet a certain quantitative threshold. The new guidance is effective for annual periods beginning after December 15, 2024. The Company is currently evaluating the impact of this guidance on the Company's financial disclosures. Adoption of the update will not impact the Company's financial position, results of operations or liquidity.

Income Statement –Expense Disaggregation Disclosures. In November 2024, the FASB issued an accounting standard update which requires disaggregated disclosures of income statement expenses for public business entities. The guidance will require companies to disclose disaggregated information about specific natural expense categories underlying certain income statement expense line items that are considered relevant because they include one or more of the five natural expense categories, as applicable: (1) purchase of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, and (5) depreciation, depletion and amortization ("DD&A") recognized as part of oil and gas producing activities or other depletion expenses. The new guidance is effective for annual periods beginning after December 15, 2024. The Company is currently evaluating the impact of this guidance on the Company's financial disclosures. Adoption of the update will not impact the Company's financial position, results of operations or liquidity.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

Note 3. Revenues

Revenue from contracts with customers

Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas, residue gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as gathering, processing and transportation and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered.

Disaggregation of Revenue

The Company has identified three material revenue streams in its business: oil, natural gas and NGLs. The following table presents the Company's revenues disaggregated by revenue stream.

	For the Year Ended December 31,	
	2024	2023
	(in thousands)	
Revenues		
Oil	$ 220,380	$ 205,663
NGLs	26,789	29,432
Natural gas	35,823	53,176
Oil and natural gas sales	$ 282,992	$ 288,271

Contract Balances

Under its sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. Accordingly, its contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to the Company's revenue contracts with customers were $28.5 million and $31.1 million at December 31, 2024 and 2023, respectively.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's contracts that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606, 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. Under the Company's contracts, 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. For the Company's contracts that have a contract term of one year or less, the Company has utilized the practical expedient in ASC 606, which states that a company is not required to disclose 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.

Note 4. Acquisitions and Divestitures

Acquisition and divestiture related expenses for third-party transactions are included in general and administrative expense in the accompanying statements of operations for the periods indicated below (in thousands):

For the Year Ended December 31,	
2024	2023
$ 1,633	$ 219

During the year ended December 31, 2024, the Company sold certain rights, title and interest in assets located in East Texas to a third party. The Company recorded a gain of approximately $1.4 million, as reflected in the (gain) loss on sale of properties in the Consolidated Statements of Operations.

Subsequent Events. On January 15, 2025, the Company announced that it entered into a definitive merger agreement with privately held Juniper Capital Advisors, L.P. ("Juniper") to combine with certain Juniper portfolio companies that own substantial oil-weighted producing assets and significant leasehold interests in the Denver-Julesburg Basin and Powder River Basin. See Note 21 for additional information related to the Mergers (as defined below).

On January 15, 2025, the Company purchased and sold certain rights, title and interest in assets in East Texas from a third party, whereby the Company received net proceeds of $6.2 million.

Note 5. Fair Value Measurements of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

Level 1 — Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is one in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. At December 31, 2024 and 2023, all of the derivative instruments reflected on the accompanying balance sheets were considered Level 2.

Level 3 — Measure based on prices or valuation models that require inputs that are both significant to the fair value measurement and are less observable from objective sources (i.e., supported by little or no market activity).

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The carrying values of cash and cash equivalents (Level 1), accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements with variable rates included in the accompanying balance sheets approximated fair value at December 31, 2024 and 2023. The fair value estimates are based upon observable market data and are classified within Level 2 of the fair value hierarchy. These assets and liabilities are not presented in the following tables. See Note 9 for the estimated fair value of our outstanding fixed-rate debt.

The fair market values of the derivative financial instruments reflected on the balance sheets as of December 31, 2024 and 2023 were based on estimated forward commodity prices (including nonperformance risk). Nonperformance risk is the risk that the obligation related to the derivative instrument will not be fulfilled. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement in its entirety. The significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table presents the derivative assets and liabilities that are measured at fair value on a recurring basis at December 31, 2024 and December 31, 2023 for each of the fair value hierarchy levels:

	Fair Value Measurements at December 31, 2024			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
		(In thousands)		
Assets:				
Commodity derivatives	$ —	$ 14,317	$ —	$ 14,317
Interest rate derivatives	—	—	—	—
Total assets	$ —	$ 14,317	$ —	$ 14,317
Liabilities:				
Commodity derivatives	$ —	$ 7,699	$ —	$ 7,699
Interest rate derivatives	—	—	—	—
Total liabilities	$ —	$ 7,699	$ —	$ 7,699

	Fair Value Measurements at December 31, 2023			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
		(In thousands)		
Assets:				
Commodity derivatives	$ —	$ 39,439	$ —	$ 39,439
Interest rate derivatives	—	—	—	—
Total assets	$ —	$ 39,439	$ —	$ 39,439
Liabilities:				
Commodity derivatives	$ —	$ 12,365	$ —	$ 12,365
Interest rate derivatives	—	—	—	—
Total liabilities	$ —	$ 12,365	$ —	$ 12,365

See Note 6 for additional information regarding our derivative instruments.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis, as reflected on the balance sheets. The following methods and assumptions are used to estimate the fair values:

- The fair value of asset retirement obligations ("AROs") is based on discounted cash flow projections using numerous estimates, assumptions, and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate; and inflation rates. The initial fair value estimates are based on unobservable market data and are classified within Level 3 of the fair value hierarchy. See Note 7 for a summary of changes in AROs.

- If sufficient market data is not available, the determination of the fair values of proved and unproved properties acquired in transactions accounted for as business combinations are prepared by utilizing estimates of discounted cash flow projections. The factors to determine fair value include, but are not limited to, estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital. The fair value of supporting equipment, such as plant assets, acquired in transactions accounted for as business combinations is commonly estimated using the depreciated replacement cost approach.

- Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. The Company uses an income approach based on the discounted cash flow method, whereby the present value of expected future net cash flows are discounted by applying an appropriate discount rate, for purposes of placing a fair value on the assets. The future cash flows are based on management's estimates for the future. The unobservable inputs used to determine fair value include, but are not limited to, estimates of proved reserves, estimates of probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties (some of which are Level 3 inputs within the fair value hierarchy).

    (i) No impairment expense on our proved oil and natural gas properties or support equipment was recorded for the year ended December 31, 2024 and 2023.

Note 6. Risk Management and Derivative Instruments

Derivative instruments are utilized to manage exposure to commodity price fluctuations and achieve a more predictable cash flow in connection with natural gas and oil sales from production. These transactions limit exposure to declines in prices but also limit the benefits that would be realized if prices increase.

Certain inherent business risks are associated with commodity and interest derivative contracts, including market risk and credit risk. Market risk is the risk that the price of natural gas or oil will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the counterparty to a contract. It is our policy to enter into derivative contracts, only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our previous and current credit agreement are counterparties to our derivative contracts. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. The Company enters into International Swaps and Derivatives Association Master Agreements ("ISDA Agreements") with each of its counterparties. The terms of the ISDA Agreements provide the Company and each of its counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or its counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. As a result, had certain counterparties failed completely to perform according to the terms of the existing contracts, we would have the right to offset \$6.6 million against amounts outstanding under our Revolving Credit Facility at December 31, 2024. See Note 9 for additional information regarding the Company's Revolving Credit Facility.

Commodity Derivatives

A combination of commodity derivatives (e.g., floating-for-fixed swaps, put options, costless collars, and three-way collars) is used to manage exposure to commodity price volatility.

The Company enters into natural gas derivative contracts that are indexed to NYMEX Henry-Hub. The Company also enters into oil derivative contracts indexed to either NYMEX WTI or Inter-Continental Exchange ("ICE") Brent. Its NGL derivative contracts are indexed to Oil Price Information Service Mont Belvieu.

At December 31, 2024, the Company had the following open commodity positions:

	2025	2026
Natural Gas Derivative Contracts:		
Fixed price swap contracts:		
Average monthly volume (MMBtu)	585,000	500,000
Weighted-average fixed price	$ 3.75	$ 3.79
Collar contracts:		
Two-way collars		
Average monthly volume (MMBtu)	500,000	500,000
Weighted-average floor price	$ 3.50	$ 3.55
Weighted-average ceiling price	$ 3.90	$ 4.06
Crude Oil Derivative Contracts:		
Fixed price swap contracts:		
Average monthly volume (Bbls)	118,167	47,750
Weighted-average fixed price	$ 71.09	$ 69.76
Collar contracts:		
Two-way collars		
Average monthly volume (Bbls)	59,500	—
Weighted-average floor price	$ 70.00	$ —
Weighted-average ceiling price	$ 80.20	$ —

Balance Sheet Presentation

The following table summarizes both: (i) the gross fair value of derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the balance sheet and (ii) the net recorded fair value as reflected on the balance sheet at December 31, 2024 and 2023. There was no cash collateral received or pledged associated with its derivative instruments since all of the counterparties, or certain of their affiliates, to its derivative contracts are lenders under the Company's Credit Agreement (as defined below).

Type	Balance Sheet Location	Asset Derivatives December 31, 2024	Liability Derivatives December 31, 2024	Asset Derivatives December 31, 2023	Liability Derivatives December 31, 2023
		(In thousands)			
Commodity contracts	Short-term derivative instruments	$ 9,499	$ 3,114	$ 21,657	$ 3,988
Interest rate swaps	Short-term derivative instruments	—	—	—	—
Gross fair value		9,499	3,114	21,657	3,988
Netting arrangements		(3,114)	(3,114)	(3,988)	(3,988)
Net recorded fair value	Short-term derivative instruments	$ 6,385	$ —	$ 17,669	$ —
Commodity contracts	Long-term derivative instruments	$ 4,818	$ 4,585	$ 17,782	$ 8,377
Interest rate swaps	Long-term derivative instruments	—	—	—	—
Gross fair value		4,818	4,585	17,782	8,377
Netting arrangements		(4,585)	(4,585)	(8,377)	(8,377)
Net recorded fair value	Long-term derivative instruments	$ 233	$ —	$ 9,405	$ —

(Gains) Losses on Derivatives

The Company does not designate derivative instruments as hedging instruments for accounting and financial reporting purposes. Accordingly, all gains and losses, including changes in the derivative instruments' fair values, have been recorded in the accompanying statements of operations. The following table details the gains and losses related to derivative instruments for the periods indicated (in thousands):

	Statements of Operations Location	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Commodity derivative contracts	Loss (gain) on commodity derivatives	$ 2,047	$ (40,343)

Note 7. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the Company's portion of future plugging and abandonment of wells and related facilities. The following table presents the changes in the asset retirement obligations for the years ended December 31, 2024 and 2023 (in thousands):

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Asset retirement obligations at beginning of period	$ 123,494	$ 116,438
Liabilities added from acquisition or drilling	1	5
Liabilities settled	(1,170)	(1,236)
Accretion expense	8,438	7,951
Revision of estimates	314	336
Asset retirement obligation at end of period	131,077	123,494
Less: Current portion	1,377	1,493
Asset retirement obligations - long-term portion	$ 129,700	$ 122,001

Note 8. Restricted Investments

Various restricted investment accounts fund certain long-term contractual and asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Beta oil and gas properties. The components of the restricted investment balances are as follows:

	December 31, 2024	December 31, 2023
	(In thousands)	
BOEM platform abandonment (See Note 18)	$ 25,448	$ 15,509
SPBPC Collateral:		
Contractual pipeline and surface facilities abandonment	4,545	4,426
Restricted investments	$ 29,993	$ 19,935

Note 9. Long-Term Debt

The Company's consolidated debt obligations consisted of the following at the dates indicated:

	December 31, 2024	December 31, 2023
	(In thousands)	
Revolving Credit Facility [1]	$ 127,000	$ 115,000
Total long-term debt	$ 127,000	$ 115,000

(1) The carrying amount of the Company's Revolving Credit Facility approximates fair value because the interest rates are variable and reflective of market rates.

Amended and Restated Credit Agreement

On July 31, 2023, OLLC and Amplify Acquisitionco LLC ("Acquisitionco"), as the direct parent of OLLC and wholly owned subsidiary of the Company, entered into the Amended and Restated Credit Agreement (the "Credit Agreement"), providing for a senior secured reserve-based revolving credit facility (the "Revolving Credit Facility"). The Revolving Credit Facility is guaranteed by the Company and all of its material subsidiaries and secured by substantially all of its assets. The Revolving Credit Facility matures on July 31, 2027, and is a replacement in full of the prior Revolving Credit Facility, by and among OLLC, Acquisitionco, the guarantors party thereto, the lenders party thereto and KeyBank National Association, as administrative agent (as amended, the "Prior Revolving Credit Facility").

The aggregate principal amount of loans outstanding under the Revolving Credit Facility as of December 31, 2024, was $127.0 million. The borrowing base under the facility is $145.0 million with elected commitments of $145.0 million at December 31, 2024. The Revolving Credit Facility borrowing base will be redetermined on a semi-annual basis based on an engineering report with respect to the Company's estimated oil, NGL, and natural gas reserves, which will take into account the prevailing oil, NGL and natural gas prices at such time, as adjusted for the impact of commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base.

Certain key terms and conditions under the Revolving Credit Facility include (but are not limited to):

- A maturity date of July 31, 2027;
- The loans shall bear interest at a rate per annum equal to (i) adjusted SOFR or (ii) an adjusted base rate, plus an applicable margin based on a utilization ratio of the lesser of the borrowing base and the aggregate commitments. The applicable margin ranges from 2.00% to 3.00% for adjusted base rate borrowings, and 3.00% to 4.00% for adjusted SOFR borrowings;
- The unused commitments under the facility will accrue a commitment fee of 0.50%, payable quarterly in arrears;
- Certain financial covenants, including the maintenance of (i) a net debt leverage ratio not to exceed 3.00 to 1.00, determined as of the last day of each fiscal quarter for the four fiscal-quarter period then ending and (ii) a current ratio of not less than 1.00 to 1.00, determined as of the last day of each fiscal quarter, in each case commencing with the fiscal quarter ending December 31, 2023;
- Certain events of default, including, without limitation: non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy; and
- Initial minimum hedging requirements covering 75% of the reasonably projected monthly production of hydrocarbons from proved developed producing reserves for the 24-month period following the effective date of the Revolving Credit Facility (the "First Period") and (ii) 50% for the 12-month period immediately following the First Period.

On October 25, 2024, OLLC entered into an amendment to the Revolving Credit Facility, which, among other things, (i) reduced the borrowing base under the Revolving Credit Facility from $150.0 million to $145.0 million, (ii) increased the aggregate elected commitments under the Revolving Credit Facility from $135.0 million to $145.0 million and (iii) amended certain interest rates applicable to loans under the Revolving Credit Facility. The next redetermination is expected in the spring of 2025.

Debt Compliance

As of December 31, 2024, the Company was in compliance with all the financial (current ratio and total leverage ratio) and non-financial covenants associated with the Company's Revolving Credit Facility.

Weighted-Average Interest Rates

The following table presents the weighted-average interest rates paid on variable-rate debt obligations for the periods presented:

	For the Year Ended December 31,	
	2024	**2023**
Revolving Credit Facility	9.27 %	9.35 %

Letters of credit

At December 31, 2024, the Company had no letters of credit outstanding.

Unamortized Deferred Financing Costs

Unamortized deferred financing costs associated with the Revolving Credit Facility was $3.3 million at December 31, 2024. The unamortized deferred financing costs are amortized over the remaining life of the Revolving Credit Facility using the straight-line method, which generally approximates the effective interest method.

Note 10. Equity (Deficit)

Equity Outstanding

The Company's authorized capital stock includes 250,000,000 shares of common stock, $0.01 par value per share. The following table summarizes the changes in the number of outstanding common units and shares of common stock:

	Common Stock
Balance, December 31, 2022	38,459,731
Issuance of common stock	—
Restricted stock units vested	967,374
Shares withheld for taxes (1)	(279,900)
Balance, December 31, 2023	39,147,205
Issuance of common stock	—
Restricted stock units vested	911,536
Shares withheld for taxes (1)	(263,603)
Balance, December 31, 2024	39,795,138

(1) Represents the net settlement on vesting of restricted stock to satisfy the tax withholding requirements.

Note 11. Earnings (Loss) per Share

The following sets forth the calculation of earnings (loss) per share, or EPS, for the periods indicated (in thousands, except per share amounts):

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Net income (loss)	$ 12,946	$ 392,750
Less: Net income allocated to participating securities	622	17,599
Basic and diluted earnings available to common stockholders	$ 12,324	$ 375,151
Common shares:		
Common shares outstanding — basic	39,655	38,961
Dilutive effect of potential common shares	—	—
Common shares outstanding — diluted	39,655	38,961
Net earnings (loss) per share:		
Basic	$ 0.31	$ 9.63
Diluted	$ 0.31	$ 9.63

Note 12. Equity-based Awards

In May 2021, the Company shareholders approved a new Equity Incentive Plan ("EIP") in which the Legacy Amplify MIP and the Legacy Amplify 2017 Non-Employee Directors Compensation Plan (the "Legacy Amplify Non-Employee Directors Compensation Plan") were replaced by the EIP and no further awards will be allowed to be granted under the Legacy Amplify MIP or the Legacy Amplify Non-Employee Directors Compensation Plan.

On May 15, 2024, the Company's shareholders approved the Amplify Energy Corp. 2024 Equity Incentive Plan (the "2024 EIP"), which had previously been approved by the board of directors of the Company (the "Board"). No further awards will be granted under the prior Legacy Equity Incentive Plan ("EIP," and together with the 2024 EIP, the "EIP Plans").

The 2024 EIP Plan provides for awards that can be granted in the form of nonqualified stock options, incentive stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance awards, stock awards and other incentive awards. To the extent that an award granted under either of the EIP Plans is canceled, expired, forfeited, settled in cash or otherwise terminated without delivery of shares of common stock, the shares of Common Stock retained by or returned to the Company will be available for future awards under the 2024 EIP. Any shares that are tendered by a participant or withheld by the Company (i) in payment of the exercise, base or purchase price relating to a stock option or stock appreciation right under either of the EIP Plans, or (ii) to satisfy any taxes or tax withholding obligations with respect to a stock option or stock appreciation right under either of the EIP Plans, as applicable, will not be available for future awards under the 2024 EIP. Any shares that are withheld by the Company or tendered by a participant to satisfy tax withholding obligations associated with any award other than stock options or stock appreciation rights granted under the 2024 EIP will become available again for future awards under the 2024 EIP. The 2024 EIP is administered by the Board. At December 31, 2024, the Company had 1,889,359 shares remaining available for issuance under the 2024 EIP.

Restricted Stock Units

Restricted Stock Units with Service Vesting Condition

Restricted stock units with service vesting conditions ("TSUs") are accounted for as equity-classified awards or liability-classified awards. The grant-date fair value is recognized as compensation cost on a straight-line basis over the requisite service period and forfeitures are accounted for as they occur. The Company considered its intent and ability to settle awards in cash or shares of stock in determining whether to classify the awards as equity or liability awards. Compensation costs for equity-classified awards are recorded as general and administrative expense. The fair value of liability-classified awards is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general administrative expense and are remeasured at fair value each reporting period.

In February 2024, the Company granted contingent cash-settlement awards in the form of TSUs (the "2024 TSUs"). In May 2024, the Company received shareholder approval of the 2024 EIP, which nullified the contingent cash settlement component for the 2024 TSUs. As of June 30, 2024, the 2024 TSUs were reclassified as equity awards. The compensation cost related to these awards is determined by the fair value of the award on the modification date. The 2024 TSUs will vest in substantially equal installments over a three-year period.

The unrecognized cost associated with TSUs was $5.5 million at December 31, 2024. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of 1.8 years.

The following table summarizes information regarding the TSUs granted under the EIP for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
TSUs outstanding at December 31, 2022	1,502,556	$ 3.82
Granted [2]	713,689	$ 8.07
Forfeited	(72,095)	$ 6.05
Vested	(812,694)	$ 4.16
TSUs outstanding at December 31, 2023	1,331,456	$ 5.77
Granted [3]	858,314	$ 6.37
Forfeited	(5,922)	$ 5.04
Vested	(804,492)	$ 5.29
TSUs outstanding at December 31, 2024	1,379,356	$ 6.43

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of TSUs issued for the year ended December 31, 2023 was $5.8 million based on a grant date market price ranging from $6.52 to $8.91 per share.
(3) The aggregate grant date fair value of TSUs issued for the year ended December 31, 2024 was $5.5 million based on a grant date market price ranging from $6.26 to $6.72 per share.

Restricted Stock Units with Market and Service Vesting Conditions

Restricted stock units with market and service vesting conditions ("PRSUs") are accounted for as equity-classified awards or liability-classified awards. The grant-date fair value is recognized as compensation cost on a graded-vesting basis. The fair value of the awards is estimated on their grant dates using a Monte Carlo simulation.

The Company recognizes compensation cost over the requisite service or performance period. The Company accounts for forfeitures as they occur. Compensation costs are recorded as general and administrative expense. The unrecognized cost associated with these awards was $2.8 million at December 31, 2024. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of approximately 1.7 years.

2022 and 2023 PRSU Awards

The 2022 and 2023 PRSU awards are accounted for as equity-classified awards and were issued with a three-year vesting period beginning on the grant date and ending on the third anniversary of the grant date. The three-year performance period for the 2022 awards is January 1, 2022 through December 31, 2024. The three-year performance period for the 2023 awards is January 1, 2023 through December 31, 2025. Vesting of PRSUs can range from zero to 200% of the target units granted based on the Company's relative total shareholder return as compared to the total shareholder return of the Company's performance peer group over the applicable performance period.

2024 PRSU Award

In February 2024, the Company granted contingent cash-settlement awards in the form of PRSUs (the "2024 PRSUs"). In May 2024, the Company received shareholder approval of the 2024 EIP, which nullified the contingent cash settlement component for the 2024 PRSUs. As of June 30, 2024, the 2024 PRSUs were reclassified as equity awards with a three-year vesting period. The compensation cost related to these awards is determined by the fair value of the award on the modification date. The three-year performance period for the 2024 PRSUs is January 1, 2024 through December 31, 2026.

The below table reflects the ranges for the assumptions used in the Monte Carlo model for the 2024 and 2023 PRSUs awards:

	Modification Date: May 2024	Date of Grant: February 2024	April 2023	February 2023
Expected volatility	63.2 %	75.8 %	92.5 %	119.2 %
Dividend yield	0.00 %	0.00 %	0.00 %	0.00 %
Risk-free interest rate	4.72 %	4.19 %	3.78 %	3.74 %

The following table summarizes information regarding the PRSUs granted under the EIP for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
PRSUs outstanding at December 31, 2022	380,512	$ 4.28
Granted (2)	321,436	$ 10.59
Forfeited	(144,567)	$ 6.55
Vested	(154,680)	$ 2.20
PRSUs outstanding at December 31, 2023	402,701	$ 9.31
Granted (3)	312,843	$ 7.55
Forfeited	—	$ —
Vested	(107,044)	$ 2.63
PRSUs outstanding at December 31, 2024	608,500	$ 9.58

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of PRSUs issued for the year ended December 31, 2023 was $3.4 million based on a calculated fair value price ranging from $1.27 to $15.04 per share.
(3) The aggregate grant date fair value of PRSUs issued for the year ended December 31, 2024 was $2.4 million based on a calculated fair value price ranging from $2.63 to $8.33 per share.

Compensation Expense

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Share-based compensation costs		
TSUs	$ 4,877	$ 4,336
PRSUs	1,922	944
	$ 6,799	$ 5,280

Note 13. Leases

The Company enters into leases for office space, warehouse space and equipment in our corporate office and operating regions as well as vehicles, compressors and surface rentals related to our business operations. In addition, the Company has right-of-way leases to operate the San Pedro Bay Pipeline. For the year ended December 31, 2024, the Company leases qualify as operating leases and the Company did not have any existing or new leases qualifying as financing leases. Most of the Company's leases, other than the Company's corporate office lease, have an initial term and may be extended on a month-to-month basis after expiration of the initial term. Most of our leases can be terminated with 30-day prior written notice. The majority of our month-to-month leases are not included as a lease liability in the Company's balance sheet because continuation of the lease is not reasonably certain. Additionally, the Company elected the short-term practical expedient to exclude leases with a term of twelve months or less.

The Company corporate office lease does not provide an implicit rate. To determine the present value of the lease payments, the Company uses an incremental borrowing rate based on the information available at the inception date. To determine the incremental borrowing rate, the Company applied a portfolio approach based on the applicable lease terms and the current economic environment. The Company uses a reasonable market interest rate for the Company office equipment and vehicle leases.

For the year ended December 31, 2024 and 2023, the Company recognized approximately $2.0 million and $2.1 million, respectively, of costs relating to the operating leases in the Consolidated Statements of Operations.

The following table presents the Company's right-of-use assets and lease liabilities for the period presented:

	December 31, 2024	December 31, 2023
	(In thousands)	
Right-of-use asset	$ 4,540	$ 5,756
Lease liabilities:		
Current lease liability	1,784	1,737
Long-term lease liability	3,683	5,090
Total lease liability	$ 5,467	$ 6,827

The following table reflects the Company's maturity analysis of the minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year (in thousands):

	Office and warehouse leases	Leased vehicles and office equipment	Total
2025	$ 1,433	$ 702	$ 2,135
2026	1,210	216	1,426
2027	838	122	960
2028	721	—	721
2029 and thereafter	1,081	—	1,081
Total lease payments	5,283	1,040	6,323
Less: interest	782	74	856
Present value of lease liabilities	$ 4,501	$ 966	$ 5,467

The weighted average remaining lease terms and discount rate for all of the Company's operating leases for the period presented:

	December 31, 2024	December 31, 2023
Weighted average remaining lease term (years):		
Office and warehouse space	3.71	4.28
Vehicles	0.26	0.42
Office equipment	—	0.01
Weighted average discount rate:		
Office and warehouse space	5.43 %	5.22 %
Vehicles	1.31 %	1.22 %
Office equipment	0.02 %	0.07 %

Note 14. Supplemental Disclosures to the Consolidated Balance Sheet and Condensed Statement of Cash Flows

Accrued Liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	December 31, 2024	December 31, 2023
Accrued lease operating expense	$ 13,845	$ 14,239
Accrued general and administrative expense	6,281	5,335
Accrued capital expenditures	5,191	8,019
Accrued liability - pipeline incident	4,434	9,331
Accrued production and ad valorem tax	2,827	3,502
Accrued commitment fee and other expense	2,395	2,626
Accrued liability - current portion of pipeline incident settlement	1,100	2,000
Operating lease liability	1,784	1,737
Asset retirement obligations	1,377	1,493
Accrued current income tax payable	116	—
Accrued interest payable	292	1,792
Other	3,771	797
Accrued liabilities	$ 43,413	$ 50,871

Accounts Receivable

Accounts receivable consisted of the following at the dates indicated (in thousands):

	December 31, 2024	December 31, 2023
Oil and natural gas receivables	$ 28,505	$ 31,131
Insurance receivable - pipeline incident	4,722	3,571
Joint interest owners and other	8,214	6,042
Total accounts receivable	41,441	40,744
Less: allowance for doubtful accounts	(1,728)	(1,648)
Total accounts receivable, net	$ 39,713	$ 39,096

Supplemental Cash Flows

Supplemental cash flow for the periods presented (in thousands):

	For the Year Ended December 31, 2024	2023
Supplemental cash flows:		
Cash paid for interest, net of amounts capitalized	$ 11,706	$ 10,992
Cash paid for taxes	1,189	5,773
Noncash investing and financing activities:		
Increase (decrease) in capital expenditures in payables and accrued liabilities	(5,428)	6,786

Note 15. Related Party Transactions

Related Party Agreements

There have been no transactions between the Company and a related person in which the related person had a direct or indirect material interest for the years ended December 31, 2024 and 2023.

Note 16. Segment Reporting

The Company's operations are all related to the exploration, development and production of oil and natural gas in the United States, from which the Company derives all of its revenues. The Company manages its business as a single reportable segment, as its operations are focused on assets with similar economic characteristics, production processes, types of purchasers, regulatory environment and customers which are consistent across the Company. Therefore, the Company aggregates its operating regions into one reportable segment.

The Chief Operating Decision Maker ("CODM") is the Company's Chief Executive Officer, who reviews the financial information on a consolidated basis. The CODM uses consolidated net income to assess financial performance, allocating capital and other resources. The CODM uses consolidated net income in the annual budgeting and monthly forecasting process. Additionally, our CODM is regularly provided information on lease operating expense, gathering, processing and transportation and taxes other than income. Other segment items primarily consists of DD&A, accretion expense, general and administrative expense, pipeline incident loss, loss (gain) on commodity derivative, interest expense and income tax expense (benefit). Our significant segment expenses and other segment items are derived from and can be found within the Consolidated Statement of Operations.

The following table provides financial information with respect to the Company's single reportable segment for the years ended December 31, 2024 and 2023:

	For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
Revenue	$ 294,681	$ 307,596
Less:		
Lease operating expense	142,950	138,361
Gathering, processing and transportation	18,427	20,808
Taxes other than income	20,895	22,574
Other segment items	99,463	(266,897)
Net income (loss)	$ 12,946	$ 392,750

Note 17. Beta Pipeline Incident

On October 2, 2021, contractors operating under the direction of Beta Operating Company, LLC, a subsidiary of the Company, observed an oil sheen on the water approximately four miles off the coast of Newport Beach, California (the "Incident"). Beta platform personnel were notified and promptly initiated the Company's Oil Spill Response Plan. On October 3, 2021, a Unified Command, consisting of the Company, the U.S. Coast Guard and California Department of Fish and Wildlife's Office of Spill Prevention and Response, was established to respond to the Incident.

On October 5, 2021, the Unified Command announced that reports from its contracted commercial divers and Remotely Operated Vehicle footage indicated that a 4,000-foot section of the Company's pipeline had been displaced with a maximum lateral movement of approximately 105 feet and that the pipeline had a 13-inch split, running parallel to the pipe. On October 14, 2021, the U.S. Coast Guard announced that it had a high degree of confidence the size of the release was approximately 588 barrels of oil. On October 16, 2021, the U.S. Coast Guard announced that it had identified the Mediterranean Shipping Company (DANIT) as a "vessel of interest" and its owner Dordellas Finance Corporation and operator Mediterranean Shipping Company, S.A. as parties in interest in connection with an anchor-dragging incident in January 2021 (the "Anchor Dragging Incident"), which occurred in close proximity to the Company's pipeline, and that additional vessels of interest continued to be investigated. On November 19, 2021, the U.S. Coast Guard announced that it had identified the COSCO (Beijing) as another vessel involved in the Anchor Dragging Incident and named its owner Capetanissa Maritime Corporation of Liberia and its operator V.Ships Greece Ltd. as parties in interest. The cause, timing and details regarding the Incident remain under investigation.

At the height of the Incident response, the Company deployed over 1,800 personnel working under the guidance and at the direction of the Unified Command to aid in cleanup operations. As of October 14, 2021, all beaches that had been closed following the Incident have reopened. On February 2, 2022, the Unified Command announced that response and monitoring efforts have officially concluded for the Incident, and Unified Command would stand down as of such date. Amplify is grateful to its Unified Command partners for their collaboration and professionalism over the course of the response.

On April 10, 2023, the Company announced that it had received the required approvals from federal regulatory agencies to restart operations at the Beta Field. The pipeline has been operated in accordance with the restart procedures that were reviewed and approved by PHMSA.

As previously disclosed, the Company reached resolutions regarding criminal and civil claims against it related to the Incident. Certain obligations, as detailed in prior disclosures, are ongoing (including certain installment payments and probation terms under a federal plea agreement). The Company also reached resolutions related to civil claims the Company asserted against third parties related to the Incident.

Federal agencies may or have commenced investigations and proceedings and may initiate enforcement actions seeking penalties and other relief under the Clean Water Act and other statutes. Amplify continues to comply with all regulatory requirements and investigations. The outcomes of these investigations and the nature of any remedies pursued will depend on the discretion of the relevant authorities and may result in regulatory or other enforcement actions, as well as civil liability.

Under the Oil Pollution Act of 1990 ("OPA 90"), the Company's pipeline was designated by the U.S. Coast Guard as the source of the oil discharge and therefore the Company is financially responsible for remediation and for certain costs and economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages. The Company has completed processing covered claims under OPA 90. In addition, the Natural Resource Damage Assessment remains ongoing and therefore the extent, timing and cost related to such assessment are difficult to project. While the Company anticipates insurance will reimburse it for expenses related to the Natural Resource Damage Assessment, any potentially uncovered expenses may be material and could impact the Company's business and results of operations and could put pressure on its liquidity position going forward.

Based on presently enacted laws and regulations and currently available facts, the Company estimates that the total costs it has incurred or will incur with respect to the Incident to be approximately $190.0 million to $210.0 million, which includes (i) actual and projected response and remediation under the direction of the Unified Command, (ii) fines and penalties of $12.0 million resulting from the resolution of the federal and state of California matters discussed above, and (iii) certain legal fees.

The range of total costs is based on the Company's assumptions regarding (i) settlement of costs associated with certain vendors for response and remediation expenses, (ii) resolution of certain third-party claims, excluding claims with respect to losses, which are not probable or reasonably estimable, and (iii) future claims and lawsuits. While the Company believes it has accurately reflected all probable and reasonably estimable costs incurred in the Company's Unaudited Consolidated Statements of Operations, these estimates are subject to uncertainties associated with the underlying assumptions. For example, settlements with vendors for response and remediation expenses may be significantly higher or lower than the Company has currently estimated. Accordingly, as the Company's assumptions and estimates may change in future periods based on future events, the Company can provide no assurance that total costs will not materially change in future periods.

The Company's estimates do not include (i) the nature, extent and cost of future legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Incident, (ii) any lost revenue associated with the suspension of operations at Beta, (iii) any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where the Company currently regards the likelihood of loss as being only reasonably possible or remote and (iv) the costs associated with the permanent repair of the pipeline and the restart of the Beta operations.

In accordance with customary insurance practice, the Company maintains insurance policies, including loss of production income insurance, against many potential losses or liabilities arising from its operations and at costs that the Company believes to be economic. The Company regularly reviews its risk of loss and the cost and availability of insurance and revises its insurance accordingly. The Company's insurance does not cover every potential risk associated with its operations and is subject to certain exclusions and deductibles. While the Company expects its insurance policies will cover a material portion of the total aggregate costs associated with the Incident, including but not limited to response and remediation expenses, defense costs and loss of revenue resulting from suspended operations, it can provide no assurance that its coverage will adequately protect it against liability from all potential consequences, damages and losses related to the Incident and such view and understanding is preliminary and subject to change.

On December 31, 2024 and December 31, 2023, the Company's insurance receivables were $4.7 million and $3.6 million, respectively. Excluding the costs associated with the resolution of the federal and state matters discussed above, the year ended December 31, 2024, the Company incurred response and remediation expenses, legal fees, loss load and other non-reimbursable expenses of $8.0 million. Of these costs, the Company has received or expects that it is probable that it will receive, $4.1 million in insurance recoveries. The remaining amount of $3.9 million, which primarily relates to certain costs that are not expected to be recovered under an insurance policy, are classified as "Pipeline Incident Loss" on the Company's Consolidated Statements of Operations.

Note 18. Commitments and Contingencies

Litigation and Environmental

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters.

Although the Company is insured against various risks to the extent the Company believes it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify it against liabilities arising from future legal proceedings.

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2024 and 2023, the Company had no environmental reserves recorded.

Beta Pipeline Incident

Please refer to "Note 17. Beta Pipeline Incident" for details.

Sinking Fund Trust Agreement

Beta Operating Company, LLC, a wholly owned subsidiary, assumed an obligation with a third party to make payments into a sinking fund in connection with its 2009 acquisition of the Beta properties, the purpose of which is to provide funds adequate to decommission the portion of the San Pedro Bay Pipeline that lies within state waters and the surface facilities. Under the terms of the agreement, the operator of the properties is obligated to make monthly deposits into the sinking fund account in an amount equal to $0.25 per barrel of oil and other liquid hydrocarbon produced from the acquired working interest. Interest earned in the account stays in the account. The obligation to fund ceases when the aggregate value of the account reaches $4.3 million. As of December 31, 2024, the account balance included in restricted investments was approximately $4.5 million.

Supplemental Bond for Decommissioning Liabilities Trust Agreement

Beta Operating Company, LLC has an obligation with BOEM in connection with the 2009 acquisition of the Beta properties. The Company supports this obligation with $161.3 million in A-rated surety bonds.

Pursuant to these additional collateral requirements, on December 15, 2021, the Company entered into two escrow funding agreements, a federal escrow funding agreement and a state escrow funding agreement, with its surety providers to fund interest-bearing escrow accounts on a quarterly basis to reimburse and indemnify the surety providers for any claims arising under the surety bonds related to the decommissioning of our Beta properties. As long as we continue to comply with our obligations under such escrow agreements, the surety providers party thereto have agreed to stay requests of additional collateral in the form of cash or letters of credit, certificates of deposit or other similar forms of liquid collateral. If any such additional collateral were requested, such additional collateral may negatively impact the Company's liquidity position.

In March 2024, the Company amended the federal escrow funding agreement to decrease the amount funded from $14.8 million per year to $8.0 million per year. There were no changes made to the state escrow funding agreement. The obligation ceases when the aggregate value of the account reaches $172.6 million. As of December 31, 2024, the Company has funded $25.4 million into the escrow accounts which is reflected in “Restricted Investments” on the Consolidated Balance Sheet. The table below outlines our funding commitment under these agreements at December 31, 2024 (in thousands):

	Payment Due by Period						
Funding commitment	**Total**	**2025**	**2026**	**2027**	**2028**	**2029**	**Thereafter** [(1)]
Federal escrow fund payments	$ 138,253	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 98,253
State escrow fund payments	9,213	1,034	1,034	1,034	1,034	1,034	4,043
Total sinking fund payments	$ 147,466	$ 9,034	$ 9,034	$ 9,034	$ 9,034	$ 9,034	$ 102,296

(1) The remaining payments will be made during the years of 2030 through 2042.

The expense related to the surety bonds is recorded in interest expense in the Company Statement of Consolidated Operations.

Operating Leases

The Company enters into leases for compressors, surface rentals, office space, warehouse space and equipment in our corporate office and operating regions. For the years ended December 31, 2024 and 2023, the Company recognized $10.7 million and $10.3 million of rental cost, respectively.

See Note 13 for the minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year.

Purchase Commitments

At December 31, 2024, the Company had a CO_2 purchase commitment with a third party associated with its Bairoil properties. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. The table below outlines its purchase commitments under these contracts based on pricing at December 31, 2024 (in thousands):

	Payment or Settlement Due by Period						
Purchase commitment	**Total**	**2025**	**2026**	**2027**	**2028**	**2029**	**Thereafter**
CO_2 minimum purchase commitment	$ 3,770	$ 3,770	$ —	$ —	$ —	$ —	$ —

Note 19. Income Tax

Amplify Energy is a corporation and, as a result, is subject to U.S. federal, state, and local income taxes.

The components of income tax benefit (expense) are as follows:

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Current taxes:		
Federal	$ 43	$ (4,286)
State	(275)	(531)
Total current income tax benefit (expense)	(232)	(4,817)
Deferred taxes:		
Federal	(2,433)	232,351
State	237	21,445
Total deferred income tax benefit (expense)	(2,196)	253,796
Total income tax benefit (expense)	$ (2,428)	$ 248,979

The actual income tax benefit (expense) differs from the expected amount computed by applying the federal statutory corporate tax rate of 21% in 2024 and in 2023 as follows:

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Expected tax benefit (expense) at federal statutory rate	$ (3,228)	$ (30,192)
Changes in valuation allowances	—	284,927
Non-cash compensation	189	696
Limit on executive compensation	(492)	(502)
State income tax benefit (expense), net of federal benefit	(578)	(2,430)
State rate change, net of federal benefit	293	(2,541)
State prior year adjustment	255	(380)
Marginal wells credits	1,137	—
Other	(4)	(599)
Total income tax benefit (expense)	$ (2,428)	$ 248,979

The Company's deferred income tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

	December 31, 2024	December 31, 2023
Deferred income tax assets:		
Property, plant & equipment	$ 58,226	$ 69,895
Net operating loss carryforward	180,902	179,627
Disallowed interest expense	7,494	5,580
Accrued liabilities	2,597	2,180
Other	4,993	4,093
Total deferred income tax assets:	254,212	261,375
Valuation allowance	—	—
Net deferred income tax assets	254,212	261,375
Deferred income tax liabilities:		
Derivatives	$ 1,603	$ 6,319
Other	1,009	1,260
Total deferred income tax liabilities	2,612	7,579
Net deferred income taxes	$ 251,600	$ 253,796

Net Operating Loss Carryforward. In connection with the merger with Midstates in 2019, the Company was subject to IRC §382 loss limitations on pre-merger net operating loss ("NOL") and tax attributes. As of December 31, 2024, the Company's federal NOL carryforward of $794.2 million is subject to §382 loss limitations, of which $20.9 million will expire in 2037 and $773.3 million have no expiration. All post-merger NOLs are not subject to §382 loss limitations and do not expire.

As of December 31, 2024, the Company had approximately $422.9 million of state net operating loss carryovers, of which $393.7 million have no expiration period and the remaining will expire in varying amounts beginning in 2037.

Valuation Allowance. In assessing deferred tax assets, management considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. The assessment considers all available information including, among other things, historical and forecasted taxable income and operating history, the scheduled reversal of deferred tax liabilities and available tax planning strategies. As of December 31, 2024, the Company had three years of cumulative book income. Furthermore, management determined that the Company's ability to maintain long-term profitability despite near-term changes in commodity prices and capital and operating costs demonstrated that there is sufficient positive evidence to conclude that it is more likely than not that all net deferred tax assets are realizable.

Uncertain Income Tax Position. The Company must recognize the tax effects of any uncertain tax positions that the Company may adopt if the position taken by us is more likely than not sustainable based on its technical merits. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company had no unrecognized tax benefits as of December 31, 2024.

Tax Audits and Settlements. The Company's income tax years 2021 through 2023 remain open and subject to examination by the Internal Revenue Service (IRS). For state and local jurisdictions where the Company conducts operations, the Company's 2020 through 2023 tax years remain open and subject to examination. In certain jurisdictions where the Company operates through more than one legal entity, each of which may have different open years subject to examination.

Note 20. Supplemental Oil and Gas Information (Unaudited)

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization is as follows at the dates indicated.

	December 31,	
	2024	2023
	(In thousands)	
Evaluated oil and natural gas properties	$ 942,981	$ 873,478
Support equipment and facilities	150,511	149,069
Accumulated depletion, depreciation, and amortization	(708,836)	(676,573)
Total	$ 384,656	$ 345,974

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows for the periods indicated:

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Property acquisition costs, proved	$ —	$ —
Property acquisition costs, unproved	—	—
Exploration	—	—
Development	70,945	34,742
Total	$ 70,945	$ 34,742

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

As required by the FASB and SEC, the standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. We do not believe the standardized measure provides a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and, therefore, may cause significant variability in cash flows from year to year as prices change.

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

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

We engaged CG&A to prepare our reserves estimates for all of our estimated proved reserves at December 31, 2024 and 2023. All proved reserves are located in the United States and all prices are held constant in accordance with SEC rules.

The weighted-average benchmark product prices used for valuing the reserves are based upon the average of the first-day-of-the-month price for each month within the period January through December of each year presented:

	2024	2023
Oil ($/Bbl):		
WTI (1)	$ 75.48	$ 78.22
NGL ($/Bbl):		
WTI (1)	$ 75.48	$ 78.22
Natural Gas ($/MMbtu):		
Henry Hub (2)	$ 2.13	$ 2.64

(1) The weighted average WTI price was adjusted by lease for quality, transportation fees, and a regional price differential.
(2) The weighted average Henry Hub price was adjusted by lease for energy content, compression charges, transportation fees, and regional price differentials.

The following tables set forth estimates of the net reserves for the periods indicated:

	For the Year Ended December 31, 2024			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved developed and undeveloped reserves:				
Beginning of year	41,078	226,878	19,185	98,077
Production	(3,060)	(16,836)	(1,278)	(7,144)
Revision of previous estimates	2,457	(3,506)	159	2,030
End of year	40,475	206,536	18,066	92,963
Proved developed reserves:				
Beginning of year	39,306	226,427	19,108	96,151
End of year	31,392	197,621	17,879	82,207
Proved undeveloped reserves:				
Beginning of year	1,772	451	77	1,926
End of year	9,083	8,915	187	10,756

	For the Year Ended December 31, 2023			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved developed and undeveloped reserves:				
Beginning of year	47,868	312,792	24,026	124,027
Production	(2,773)	(20,297)	(1,323)	(7,479)
Revision of previous estimates	(4,017)	(65,617)	(3,518)	(18,471)
End of year	41,078	226,878	19,185	98,077
Proved developed reserves:				
Beginning of period	47,010	312,185	23,928	122,969
End of period	39,306	226,427	19,108	96,151
Proved undeveloped reserves:				
Beginning of period	858	607	98	1,058
End of period	1,772	451	77	1,926

Noteworthy amounts included in the categories of proved reserve changes in the above tables include:

- The 5.1 MMBoe decrease in reserves for the year ended December 31, 2024 was primarily due to production of 7.1 MMBoe, a 6.9 MMBoe decrease as a result of changes in commodity prices and 4.8 MMBoe decrease primarily due higher electricity costs and shorter economic limit at Bairoil. This decrease was partially offset by the additional 31 (23 operated Beta) PUD locations which added 9.39 MMBoe, lower maintenance costs primarily at East Texas and Oklahoma of 3.36 MMBoe and a positive technical revision of 0.97 MMBoe.

- The 26.0 MMBoe decrease in reserves for the year ended December 31, 2023 was primarily due to production of 7.5 MMBoe, a 17.8 MMBoe decrease as a result of changes in commodity prices and 2.5 MMBoe decrease due to higher maintenance costs. This decrease was partially offset by the addition of 4 Beta PUD locations budgeted in 2024, which added 1.1 MMBoe and a positive technical revision of 0.7 MMBoe.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The standardized measure of discounted future net cash flows is as follows:

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Future cash inflows	$ 3,818,663	$ 4,277,014
Future production costs (1)	(2,217,101)	(2,751,065)
Future development costs (1)	(467,142)	(313,290)
Future income tax expense	(204,262)	(203,770)
Future net cash flows for estimated timing of cash flows	930,158	1,008,889
10% annual discount for estimated timing of cash flows	(321,919)	(382,759)
Standardized measure of discounted future net cash flows	$ 608,239	$ 626,130

(1) For the years ended December 31, 2024 and 2023, onshore abandonment costs are included in future production cost and offshore abandonment costs are included in future development costs.

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

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the two-year period presented:

	For the Year Ended December 31,	
	2024	2023
	(In thousands)	
Beginning of year	$ 626,130	$ 1,337,956
Changes in prices and costs	(124,770)	(798,942)
Revisions of previous quantities	142,763	(196,093)
Sale of oil and natural gas produced, net of production costs	(100,658)	(106,469)
Net change in taxes	3,356	180,530
Accretion of discount	75,701	164,937
Change in production rates and other	(23,979)	38,174
Net changes in future development costs	(2,985)	(3,669)
Previously estimated development costs incurred	12,681	9,706
End of year	$ 608,239	$ 626,130

Note 21. Subsequent Events

Merger with Juniper Capital

On January 14, 2025, the Company entered into an Agreement and Plan of Merger (the “Merger Agreement”) with Amplify DJ Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of the Company (“First Merger Sub”), Amplify PRB Operating LLC, a Delaware limited liability company and indirect wholly owned subsidiary of Amplify (“Second Merger Sub,” and together with First Merger Sub, the “Merger Subs”), North Peak Oil & Gas, LLC, a Delaware limited liability company (“NPOG”), Century Oil and Gas Sub-Holdings, LLC, a Delaware limited liability company (“COG” and, together with NPOG, each, an “Acquired Company” and, collectively, the “Acquired Companies”), and, solely for the limited purposes set forth in the Merger Agreement (as defined below), Juniper and the Specified Company Entities set forth on Annex A thereto, pursuant to which, at the effective time of the Mergers (as defined below) (the “Effective Time”), (a) NPOG will merge with and into First Merger Sub, with NPOG surviving the merger as an indirect, wholly owned subsidiary of the Company and (b) COG will merge with and into Second Merger Sub, with COG surviving the merger as an indirect, wholly owned subsidiary of the Company, in each case, subject to the terms and conditions of the Merger Agreement (clauses (a) and (b), together, the “Mergers”).

Subject to the terms and conditions of the Merger Agreement, at the Effective Time, all of the issued and outstanding limited liability company interests of each of the Acquired Companies will automatically be converted into the right to receive, in the aggregate, 26,729,315 validly issued, fully paid and nonassessable shares (the “Aggregate Merger Consideration”) of Amplify’s Common Stock. Following the Effective Time, the Company’s existing stockholders and the Acquired Companies’ existing equityholders are expected to own approximately 61% and 39%, respectively, of the combined company’s outstanding equity.

Mr. Christopher W. Hamm will serve as Chairman of our Board, and Mr. Martyn Willsher will continue to serve as the Chief Executive Officer of the Company after the Effective Time. The Merger Agreement provides that the Board will consist of the following seven members: Martyn Willsher, Christopher W. Hamm, Deborah G. Adams, James E. Craddock, Vidisha Prasad, Edward Geiser and Josh Schmidt. Further, Josh Schmidt will be appointed as Chairman of the compensation committee of the Board, and Edward Geiser will be appointed as a member of the nominating and governance committee of the Board.

The Merger Agreement contains customary representations, warranties and covenants of the Company and the Acquired Companies, including covenants relating to the conduct of the business of both the Company and the Acquired Companies from the date of signing the Merger Agreement through closing of the Mergers (the “Closing”), obtaining the requisite approval of the stockholders of the Company and maintaining the listing of the Common Stock on the NYSE. Under the terms of the Merger Agreement, the Company has also agreed not to solicit from any person an acquisition proposal for the Company.

In connection with the Mergers, the Company will seek the approval of the Company’s stockholders with respect to the issuance of the Aggregate Merger Consideration in connection with the Closing (the “Stock Issuance Proposal”). The Board has agreed to recommend the approval of the Stock Issuance Proposal to our stockholders and to solicit proxies in support of the approval of the Stock Issuance Proposal at a meeting of the stockholders (the “Stockholders Meeting”) to be held for that purpose.

The Closing is subject to various customary closing conditions, including, among other things, (a) the receipt of approval of the Stock Issuance Proposal by the affirmative vote of at least a majority of the votes cast in person or represented by proxy at the Stockholders Meeting by the holders of Common Stock entitled to vote thereon (the “Amplify Stockholder Approval”), (b) the receipt of certain specified consents, and (c) the approval for listing by the NYSE for the shares of Common Stock to be issued in connection with the Mergers.

The Merger Agreement also provides each of the Company and the Acquired Companies with certain termination rights including, among other things, termination: (a) by the Acquired Companies or Amplify Energy if Amplify Energy fails to obtain the Amplify Stockholder Approval; (b) by Amplify Energy or the Acquired Companies, if Amplify Energy or either of the Acquired Companies breaches or fails to perform any of its or their respective representations, warranties or covenants in the Merger Agreement and such breach cannot be or is not timely cured in accordance with the terms of the Merger Agreement and such breach or failure to perform would cause the applicable closing condition not to be satisfied; (c) by the Acquired Companies, in the event the Board effects a Parent Change in Recommendation (as defined in the Merger Agreement) prior to the Amplify Stockholder Approval being obtained or if Amplify Energy is in violation of the covenant to not solicit alternative business combination proposals from third parties in any material respect; or (d) by Amplify Energy, if the Acquired Companies are in violation of the covenant to not solicit alternative business combination proposals from third parties in any material respect.

In the event that a Parent Alternative Proposal (as defined in the Merger Agreement) is publicly submitted or proposed to the Board prior to, and not withdrawn at the time of the Stockholders Meeting, the Merger Agreement is terminated by the Acquired Companies in accordance with clause (b) above or by either Amplify Energy or the Acquired Companies in accordance with clause (a) above or as a result of the failure to close the Mergers on or before July 14, 2025 (the “Outside Date”), and Amplify Energy enters into a definitive agreement with respect to, or consummates, a Parent Alternative Proposal within 12 months following termination of the Merger Agreement, Amplify Energy will be required to pay the Acquired Companies a termination fee of $8,500,000 (the “Amplify Termination Fee”). Amplify Energy will also be required to pay the Acquired Companies the Amplify Termination Fee in the event the Merger Agreement is terminated by the Acquired Companies in accordance with clause (c) above. In the event that Amplify Energy terminates the Merger Agreement in accordance with clause (d) above, the Acquired Companies will be required to (or will cause the Specified Company Entities to) pay Amplify Energy a termination fee of $5,500,000 (the “Acquired Companies’ Termination Fee”). If the Merger Agreement is terminated by any party in accordance with clause (a) or by the Acquired Companies in accordance with clause (b) above and the Amplify Termination Fee is not otherwise payable in accordance with the terms and conditions of the Merger Agreement, then Amplify Energy will be required to reimburse the Acquired Companies’ incurred expenses, up to a maximum aggregate amount of $800,000. If the Merger Agreement is terminated by Amplify Energy in accordance with clause (b) above and the Acquired Companies’ Termination Fee is not otherwise payable in accordance with the terms and conditions of the Merger Agreement, then the Acquired Companies will be required to (or will cause the Specified Company Entities to) reimburse Amplify Energy’s incurred expenses, up to a maximum aggregate amount of $1,250,000. In addition to the foregoing termination rights, the Merger Agreement may be terminated by either Amplify Energy or the Acquired Companies if the Mergers have not been consummated on or prior to the Outside Date or if a governmental entity issues a final, non-appealable order or decree permanently restraining, enjoining or prohibiting the Mergers. The parties may also mutually agree to terminate the Merger Agreement.

If the Board effects a Parent Change in Recommendation prior to the Stockholders Meeting, Amplify Energy will, unless the Acquired Companies terminate the Merger Agreement, be required to submit the approval of the Amplify Stock Issuance to a vote of Amplify Energy’s stockholders at the Stockholders Meeting notwithstanding the Parent Change in Recommendation. Neither Amplify Energy nor the Acquired Companies are able to terminate the Merger Agreement in order to accept an alternative business combination proposal.

The Merger Agreement provides that, during the period from the date of the Merger Agreement until the Effective Time, each of Amplify Energy and the Acquired Companies will be subject to certain restrictions on their ability to solicit or respond to alternative business combination proposals from third parties, to provide non-public information to third parties and to engage in discussions with third parties regarding alternative business combination proposals, subject to customary exceptions.

The Merger Agreement contains customary representations, warranties and covenants for a transaction of this nature. The Merger Agreement also contains customary pre-closing covenants, including the obligations of Amplify Energy and the Acquired Companies to conduct their respective businesses in the ordinary course, consistent with past practice, and to refrain from taking certain specified actions without the consent of the other party.

Exhibit 99.1

EVALUATION SUMMARY

AMPLIFY ENERGY CORP. INTERESTS

VARIOUS OIL AND GAS PROPERTIES IN THE UNITED STATES

TOTAL PROVED RESERVES

AS OF DECEMBER 31, 2024

SEC PRICE CASE

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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AMPLIFY ENERGY CORP. INTERESTS

VARIOUS OIL AND GAS PROPERTIES IN THE UNITED STATES

TOTAL PROVED RESERVES

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SEC PRICE CASE

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS
TEXAS REGISTERED ENGINEERING FIRM F-693

W. TODD BROOKER, P.E.
PRESIDENT

MATTHEW K. REGAN, P.E.
VICE PRESIDENT

January 29, 2025

Amplify Energy Corp.
500 Dallas Street, Suite 1700
Houston, Texas 77002

Re: Evaluation Summary
Amplify Energy Corp. Interests
Total Proved Reserves
As of December 31, 2024

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Ladies and Gentlemen:

As requested, this report was completed on January 29, 2025 for Amplify Energy Corp. ("Amplify") for the purpose of public disclosure by Amplify in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. We evaluated 100% of Amplify reserves, which are made up of oil and gas properties in Alabama, federal waters offshore California, Louisiana, Oklahoma, Texas and Wyoming. This report, with an effective date of December 31, 2024, was prepared using constant prices and costs and conforms to the guidelines of the *Securities and Exchange Commission* (SEC). The results of this evaluation are presented below:

		Developed Producing	Proved Developed Non-Producing	Proved Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil.	- MBBL	29,806.7	1,584.9	31,391.6	9,083.1	40,474.7
Gas	- MMCF	173,884.8	23,736.0	197,620.9	8,915.1	206,536.0
NGL	- MBBL	16,161.5	1,717.2	17,878.7	186.8	18,065.5
Revenue						
Oil.	- M$	2,133,266.2	114,934.0	2,248,200.2	652,542.0	2,900,741.6
Gas	- M$	335,728.1	45,915.5	381,643.6	18,149.8	399,793.4
NGL	- M$	476,972.8	37,525.7	514,498.5	3,629.2	518,127.7
Severance Taxes	- M$	129,604.2	9,056.1	138,660.3	3,314.8	141,975.1
Ad Valorem Taxes.	- M$	91,994.8	2,675.4	94,670.2	1,135.2	95,805.4
Operating Expenses	- M$	1,852,140.4	81,363.6	1,933,504.0	45,816.1	1,979,320.3
Investments	- M$	258,049.9	19,125.6	277,175.5	189,966.5	467,142.1
Net Cash Flows.	- M$	614,177.0	86,154.5	700,331.5	434,088.3	1,134,419.7
Discounted @ 10% . . . . . . ***(Present Worth)***	**- M$**	**464,391.6**	**42,795.0**	**507,186.5**	**228,578.4**	**735,765.0**

(1) Operating expense includes but is not limited to, direct operating costs, maintenance, well service, compressor service, tubing/pump repair, compression fees, gathering expenses, transportation costs andwater disposal costs

(2) Investments includes but is not limited to, re-completion costs, future drilling costs, newlift installations, pumping units and the costs for plugging and salvage value of equipment at abandonment

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its “present worth”. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil and NGL volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Our estimates are for proved reserves only and do not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated. The Proved Developed category is the summation of the Proved Developed Producing and Proved Developed Non-Producing estimates.

Hydrocarbon Pricing

The base oil and gas prices calculated for December 31, 2024 were $75.48 per barrel and $2.130 per MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil price is based upon WTI-Cushing spot prices (EIA) during 2024 and the base gas price is based upon Henry Hub spot prices (Platt’s Gas Daily) during 2024.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices over the life of the proved properties was estimated to be $71.668 per barrel for oil, $1.936 per MCF for gas and $28.680 per barrel for natural gas liquids. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, severance taxes, lease operating expenses and investments were calculated and prepared by Amplify and were thoroughly reviewed by us for accuracy and completeness. Lease operating expenses were calculated based on historical lease operating statements. All economic parameters, including lease operating expenses and investments, were held constant (not escalated) throughout the life of these properties. Operating expense includes but is not limited to, direct operating costs, maintenance, well service, compressor service, tubing/pump repair, compression fees, gathering expenses, transportation costs and water disposal costs. Investments includes but is not limited to, re-completion costs, future drilling costs, new lift installations, pumping units and the costs for plugging and salvage value of equipment at abandonment.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. Amplify’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

This evaluation includes 67 commercial proved undeveloped locations. There are 25 wells in the Beta area (offshore California), 38 wells in the EGLFD area (Texas) and 4 wells in the ETX_NLA area (Texas) Each of the drilling locations proposed conform to the proved undeveloped standards as set forth by the SEC. In our opinion, Amplify has indicated they have every intent to complete this development plan as scheduled. Furthermore, Amplify has indicated that they have the proper company staffing, financial backing and prior development success to ensure this development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described in the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to offset production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing and undeveloped reserve estimates were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for Amplify properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

General Discussion

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were 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. All estimates represent our best judgment based on the data available at the time of preparation. Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

An on-site field inspection of the properties has not been performed. The mechanical operation or condition 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 cost of plugging and the salvage value of equipment at abandonment have been included on commercial proved wells at the end of the economic life of the cases in the SEC pricing evaluation. The cost of plugging and salvage value of equipment at abandonment have not been included elsewhere herein.

Cawley, Gillespie & Associates, Inc. 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. This evaluation was supervised by W. Todd Brooker, President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or Amplify Energy Corp. and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office

Yours very truly,

CAWLEY, GILLESPIE & ASSOCIATES, INC.
TEXAS REGISTERED ENGINEERING FIRM F-693

Matthew K. Regan, P.E.
Vice President

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *Production Performance*, (2) *Material Balance*, (3) *Volumetric* and (4) *Analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production Performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material Balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which make this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method which employs experience and judgment to estimate reserves is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

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

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

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

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

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

"(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"(6) **Developed oil and gas reserves**. Developed oil and gas 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 required 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.

"(31) **Undeveloped oil and gas reserves**. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

"(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

"(iii)Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **Probable reserves**. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii)Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv)See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

"(17) **Possible reserves**. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii)Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv)The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi)Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

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

"Note to paragraph (26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."

Professional Qualifications of W. Todd Brooker, P.E.
Primary Technical Person

The evaluation summarized by this report was conducted by a proficient team of geologists and reservoir engineers who integrate geological, geophysical, engineering and economic data to produce high quality reserve estimates and economic forecasts. This report was supervised by Todd Brooker, President of Cawley, Gillespie & Associates, Inc. (CG&A).

Prior to joining CG&A, Mr. Brooker worked in Gulf of Mexico drilling and production engineering at Chevron USA. Mr. Brooker has been an employee of CG&A since 1992 and became President in 2017. His responsibilities include reserve and economic evaluations, fair market valuations, expert reporting and testimony, field/reservoir studies, pipeline resource assessments, field development planning and acquisition/divestiture analysis. His reserve reports are routinely used for public company U.S. Securities and Exchange Commission (SEC) disclosures. His experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures.

Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering. He is a registered Professional Engineer in the State of Texas (License #83462), and a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE).

Based on his educational background, professional training and more than 30 years of experience, Mr. Brooker and CG&A continue to deliver independent, professional, ethical and reliable engineering and geological services to the petroleum industry.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
TEXAS REGISTERED ENGINEERING FIRM F-693

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

FORM 10-K/A

(Amendment No. 1)

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

For the fiscal year ended December 31, 2024

OR

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

For the transition period from ________ to ________
Commission File Number: 001-35512

AMPLIFY ENERGY CORP.
(Exact name of registrant as specified in its charter)

Delaware	**82-1326219**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

500 Dallas Street, Suite 1700
Houston, TX 77002
(832) 219-9001
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	AMPY	NYSE

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

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

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

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

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

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

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☒
Emerging growth company	☐		

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

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

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

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $202.1 million on June 30, 2024, based on $6.78 per share, the last reported sales price of the shares on the New York Stock Exchange on such date.

As of April 16, 2025, the registrant had 40,336,579 outstanding shares of common stock, $0.01 par value per share.

Documents Incorporated By Reference: None.

Auditor Firm ID	**Auditor Location**	**Auditor Name**
34	Houston, Texas	DELOITTE & TOUCHE LLP

EXPLANATORY NOTE

This Amendment No. 1 on Form 10-K/A (this "Form 10-K/A") to the Annual Report on Form 10-K of Amplify Energy Corp. ("Amplify Energy," "Amplify," the "Company," "we," "us," "our," or similar terms), for the fiscal year ended December 31, 2024, filed with the Securities and Exchange Commission (the "SEC") on March 5, 2025 (the "Original Form 10-K"), is being filed solely for the purpose of including the information required by Part III of Form 10-K. This information was previously omitted from the Original Form 10-K in reliance on General Instruction G(3) to Form 10-K, which permits the information in the above referenced items to be incorporated in the Form 10-K by reference from our definitive proxy statement if such statement is filed no later than 120 days after our fiscal year-end. We are filing this Form 10-K/A to include Part III information in our Form 10-K because we will not file a definitive proxy statement containing such information within 120 days after the end of the fiscal year covered by the Original Form 10-K. In addition, this Form 10-K/A deletes the reference on the cover of the Original Form 10-K to the incorporation by reference of portions of our proxy statement into Part III of the Original Form 10-K.

Pursuant to Rule 12b-15 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), this Form 10-K/A also contains certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, which are attached hereto. Because no financial statements have been included in this Form 10-K/A and this Form 10-K/A does not contain or amend any disclosure with respect to Items 307 and 308 of Regulation S-K, paragraphs 3, 4, and 5 of the certifications have been omitted.

Except as described above, this Form 10-K/A does not modify or update disclosure in, or exhibits to, the Original Form 10-K. Furthermore, this Form 10-K/A does not change any previously reported financial results. Information not affected by this Form 10-K/A remains unchanged and reflects the disclosures made at the time the Original Form 10-K was filed.

AMPLIFY ENERGY CORP.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors and Executive Officers

The following table sets forth information concerning our current executive officers and directors as of April 17, 2025.

Name	Age	Position with the Company
Eric Dulany	49	Vice President and Chief Accounting Officer
James Frew	47	Senior Vice President and Chief Financial Officer
Daniel Furbee	42	Senior Vice President and Chief Operating Officer
Tony Lopez	44	Senior Vice President, Engineering and Exploitation
Eric M. Willis	46	Senior Vice President, General Counsel and Corporate Secretary
Martyn Willsher	47	President, Chief Executive Officer and Director
Deborah G. Adams	64	Director
James E. Craddock	66	Director
Patrice Douglas	62	Director
Christopher W. Hamm	58	Director (Chairman)
Vidisha Prasad	45	Director
Todd R. Snyder	62	Director

Set forth below is biographical information for our executive officers and directors.

Executive Officers

Eric Dulany has served as Vice President and Chief Accounting Officer of Amplify Energy since May 2021. Prior to joining Amplify, Mr. Dulany served in accounting leadership roles at public companies, including at W&T Offshore, Inc. from January 2019 to March 2021, and Energy XXI Gulf Coast, Inc., Freeport McMoRan Oil and Gas LLC and Endeavour International, Inc. Mr. Dulany began his career in public accounting, having spent two years as the National Energy Practice Leader at BKD, LLP from September 2012 to September 2014 and 12 years at PricewaterhouseCoopers LLP in their Houston and London (UK) audit practices from September 2000 to August 2012. Mr. Dulany graduated from Houston Baptist University with a Bachelor of Business Administration degree in Accounting and Business Administration. He has been a CPA in the State of Texas since 2003 and is a member of the AICPA and the Texas Society of CPAs.

James Frew has served as Senior Vice President and Chief Financial Officer of Amplify Energy since April 2023. Prior to joining Amplify, Mr. Frew was a partner at Sentinel Petroleum from March 2022 to April 2023. Previously, Mr. Frew served as Executive Vice President and Chief Financial Officer of Riviera Resources, Inc. from August 2018 to October 2020, and as Linn Energy’s Vice President of Marketing and Midstream from May 2014 to August 2018 and Director of Business Development, Strategy and Planning from May 2011 to May 2014. From August 2002 to May 2011, Mr. Frew held several roles in the Natural Resources division of the J.M. Huber Corporation. Mr. Frew started his career as a management consultant at the Parthenon Group. Mr. Frew holds a Bachelor of Arts in Economics and Political Science from Williams College.

Daniel Furbee has served as Senior Vice President and Chief Operating Officer of Amplify Energy since March 2023. Prior to joining Amplify, Mr. Furbee served as a partner at Sentinel Petroleum from February 2022 to March 2023, as an independent advisor for various companies from January 2021 to January 2022, as the Executive Vice President and Chief Operating Officer of Riviera Resources, Inc. from August 2018 to December 2020, as Linn Energy Inc.’s Vice President of Asset and Business Development from March 2018 to August 2018 and as Vice President of Business Development and Asset Development for Sanchez Energy Corporation from September 2013 to February 2018. From 2005 to August 2013, Mr. Furbee served in various engineering roles of increasing responsibilities at Linn Energy, LLC. Mr. Furbee holds a Bachelor of Science in Petroleum Engineering from Marietta College and a Master of Business Administration from the University of Houston.

Tony Lopez has served as Senior Vice President, Engineering and Exploitation of Amplify Energy since August 2019. Mr. Lopez previously served as Vice President, Corporate Reserves from June 2018 until the closing of the merger with Midstates Petroleum Company, Inc. Prior to joining Amplify, Mr. Lopez previously served as Vice President of Acquisitions and Engineering for EnerVest, Ltd. from April 2014 to June 2018, where he managed the corporate reserve reporting process and the financial planning & analysis department. From 2004 to 2018, Mr. Lopez worked for EnerVest, Ltd. where he held numerous engineering positions of increasing responsibility. Mr. Lopez has over 20 years of industry experience. Mr. Lopez holds a Bachelor of Science in Petroleum and Natural Gas Engineering from West Virginia University and is an active member of the Society of Petroleum Engineers and the American Association of Petroleum Geologists.

Eric M. Willis has served as Senior Vice President, General Counsel and Corporate Secretary of Amplify Energy since August 2019. Mr. Willis previously served as Vice President and General Counsel of Amplify Energy from December 2017 to August 2019. From April 2015 to December 2017, Mr. Willis was a partner in the capital markets practice group at Kirkland & Ellis LLP in Houston, Texas, representing oil and gas clients. Prior to joining Kirkland & Ellis, he practiced corporate and securities law from September 2008 to April 2015 at Latham & Watkins LLP in Houston, Texas and Orange County, California. Mr. Willis holds a Juris Doctorate from The University of Texas at Austin School of Law and Bachelor of Science in Chemistry from the United States Military Academy.

Martyn Willsher has served as Chief Executive Officer of Amplify Energy since January 2021, after having served as interim Chief Executive Officer since April 2020. Mr. Willsher also previously served as Senior Vice President and Chief Financial Officer of Amplify Energy from April 2018 to January 2021. From May 2017 to April 2018, Mr. Willsher served as Amplify Energy’s Vice President and Treasurer. He also served as Treasurer of Memorial Production Partners GP, LLC, Amplify Energy’s predecessor, from July 2014 to May 2017, and as Director of Strategic Planning for Memorial Resource Development LLC, an affiliate of the predecessor of Amplify Energy, from March 2012 to June 2014. Prior to that, he served as Manager, Financial Analysis of AGL Resources from September 2009 to March 2012, and as Director – Upstream Oil & Gas A&D of Constellation Energy from August 2006 to March 2009. Prior to that, he served in various business development and financial analysis roles at JM Huber Corp., FTI Consulting and PricewaterhouseCoopers LLP. Mr. Willsher received his Master of Business Administration from The University of Texas at Austin and his Bachelor of Business Administration in Finance from Texas A&M University.

The Board of Directors of Amplify Energy (the “Board”) believes Mr. Willsher’s extensive experience in the oil and natural gas industry and intimate familiarity with the Company brings significant value to the Board.

Non-Employee Directors

Deborah G. Adams has served as a member of Amplify Energy’s Board since April 2022. Ms. Adams has over 35 years of energy industry experience, as a leader with particular focus on health, safety, and sustainability, project management, procurement, and transportation. Prior to retirement, Ms. Adams served as Senior Vice President of Health, Safety, and Environmental, Projects and Procurement at Phillips 66 from June 2014 to October 2016. In this role, Ms. Adams oversaw all regulatory affairs and processes, reported directly to the company’s CEO, and regularly presented to the Phillips 66 Board of Directors. She was responsible for improved safety performance across the entire company along with overseeing a number of new facilities projects worth over a billion dollars, all completed on budget and on time. Prior to this role, Ms. Adams held roles of increasing responsibility, including President Transportation and Chief Procurement Officer, at Phillips 66 and predecessor companies since 1983. Ms. Adams currently serves on the board of directors of MRC Global, where she serves as chair of the board of directors, and previously served on the board of directors of EnLink Midstream, a formerly publicly traded midstream energy services company, from March 2020 to January 2025 and Gulfport Energy (NYSE: GPOR), an oil and gas exploration and production company, from March 2018 to May 2021. She also currently serves on the board of directors of Austin Industries, a privately-held, employee-owned construction company. Ms. Adams previously served her alma mater, Oklahoma State University, as a member of the foundation board of trustees. Ms. Adams also serves as a member of the Advisory Board for the TriCities Chapter of the National Association of Corporate Directors. Ms. Adams holds a Bachelor of Science in Chemical Engineering from Oklahoma State University.

The Board believes Ms. Adams’ extensive leadership experience in the midstream and downstream businesses, procurement and information systems in the oil and natural gas industry and her health, safety and environmental expertise brings significant value to the Board.

James E. Craddock has served as a member of Amplify Energy's Board since February 2023. Mr. Craddock is a seasoned upstream executive and director who possesses broad-based technical and operational knowledge with over 30 years of experience. Previously, Mr. Craddock served as the Chairman and Chief Executive Officer of Rosetta Resources Inc., from 2013 to 2015 until its merger with Noble Energy Inc., following which Mr. Craddock served on Noble Energy Inc.'s board of directors from 2015 until the company was acquired by Chevron in 2020. Prior to that, Mr. Craddock was the Chief Operating Officer for BPI Industries Inc. and held several positions of increasing responsibility over a 20-year career at Burlington Resources Inc. He currently serves on the board of directors of Callon Petroleum Company since April 2023 and Crescent Point Energy Corp. since June 2019 and previously served on the boards of Templar Energy LLC, Noble Energy Inc. and Bonanza Creek Energy, Inc. and on the Texas Railroad Commission's Eagle Ford Shale Task Force. Mr. Craddock holds a B.S. in Mechanical Engineering from Texas A&M University.

The Board believes Mr. Craddock's extensive experience in both the technical and operational aspects of the oil and natural gas industry, including his service as Chief Executive Officer and a board member of a large oil and natural gas producer, brings significant value to the Board.

Patrice Douglas has served as a member of Amplify Energy's Board since February 2021. Ms. Douglas is an attorney, who represents financial institutions, energy companies, municipalities, and utilities on legal, regulatory and compliance matters. Previously, Ms. Douglas served as Senior Vice-President and then President of SpiritBank from 2004 to 2007 and Executive Vice-President of First Fidelity Bank from 2007 to 2011. Ms. Douglas was first elected as mayor of Edmond, Oklahoma in 2009 and was elected to a second term in 2011. As a member of the U.S. Conference of Mayors, she served on the committee for tourism. Ms. Douglas was appointed by Oklahoma's Governor to the Oklahoma Corporation Commission where she served from 2011 to 2015, having been re-elected unopposed in 2012. She was elected to be chairman of the Commission in 2012. While serving on the Commission, Ms. Douglas was a member of the National Association of Regulatory Utility Commissioners, and served on its Water Committee. Ms. Douglas has served on the board of directors of Diamond Offshore Drilling, Inc. since May 2023. Her prior experiences also include service as a member of the board of directors and chair of the nominating and governance and audit committees for Midstates Petroleum Company, Inc. from September 2016 to August 2019; a member of the board of directors for Bank SNB from August 2016 to May 2018, serving on both the audit committee and the directors' credit committee and a member of the board of directors for Southwest BanCorp. from 2016 to 2019. Ms. Douglas received a B.S. in Computer Information Systems from Oklahoma Christian University and J.D. from the University of Oklahoma.

The Board believes Ms. Douglas' considerable financial experience, as well as her extensive prior experience as a director and/or audit committee member of other exploration and production companies and financial institutions, brings valuable strategic and analytical skills to the Board.

Christopher W. Hamm has served as Amplify Energy's Chairman of the Board since January 2021. He previously served as the Lead Director of the Board from April 2020 until his appointment as Chairman, and has served as a member of Amplify Energy's Board since August 2019. Mr. Hamm previously served as a member of the board of directors of Amplify Energy from its inception in May 2017 until the closing of the merger with Midstates Petroleum Company, Inc. in August 2019. Mr. Hamm has spent the majority of his 34-year career as a founder, CEO, professional investor, advisor and director of both public and private organizations. He is currently Chairman & CEO of Axys Capital, a boutique investment bank, advisor and manager he founded in 2009, and CEO of Axys Data, a fintech company he founded in 2001. Mr. Hamm founded, and was Chairman, CEO and CIO of Memorial Investment Advisors, a registered investment advisor, and Memorial Funds, an institutional multi-fund registered investment company, where he served as Chairman and CEO. Prior to founding his own firms, Mr. Hamm served as Executive Director — Institutional Services at CIBC Oppenheimer, Senior Vice President — Capital Markets at PaineWebber, and Vice President — Taxable Fixed Income at Howard Weil Labouisse & Friederichs.

The Board believes Mr. Hamm's extensive investment experience and intimate familiarity with the Company brings significant value to the Board.

Vidisha Prasad has served as a member of Amplify Energy's Board since October 2023. Ms. Prasad brings more than two decades of experience in energy investments, strategic and board advisory, corporate mergers, asset acquisitions and divestitures, capital markets and restructuring. Ms. Prasad is currently the Managing Partner of Adya Partners, a multi-strategy investment firm focused on private secondary investments and early-stage venture capital in the energy, energy transition and technology sectors. Prior to founding Adya Partners, Ms. Prasad was a founding member of Guggenheim Securities' Energy Investment Banking practice and prior to that, Ms. Prasad held roles of increasing responsibility within Citi's Global Energy Investment Banking Groups in Houston, London and New York. Ms. Prasad previously served on the Board of Centennial Resources (now Permian Resources) where she served on the Audit, Nominating, Governance and ESG Committees. She also serves on the Board of the Grammy award winning Houston Chamber Choir, where she chairs the Development Committee. Ms. Prasad received a B.A. in Economics from the University of Rochester.

The Board believes Ms. Prasad's experience in the energy industry, particularly in the areas of capital markets, finance and M&A, as well as her knowledge and understanding of strategic planning and risk management brings significant value to the Board.

Todd R. Snyder has served as a member of Amplify Energy's Board since October 2016. Mr. Snyder is a managing director and global head of the Piper Sandler restructuring group, TRS Advisors since 2017. Prior to joining Piper Sandler, Mr. Snyder was Chief Executive Officer at TRS Advisors. Before that he was executive vice chairman of Rothschild & Co. and co-head of the North American restructuring advisory business. Previously, he was a managing director in the restructuring and reorganization group at Peter J. Solomon Company. Prior to joining Peter J. Solomon Company, Mr. Snyder was a managing director at KPMG Peat Marwick in the corporate recovery group where he was also national director of the corporate recovery practice for government enterprises (regulated and privatizing industries). Prior to his move to investment banking, he practiced law in the business reorganization department of Weil, Gotshal & Manges LLP. Mr. Snyder was a commissioner of the New York State Gaming Commission and a member of New York State's financial restructuring board for local governments. He previously served as a director of GenCorp Inc., AMC Financial, Inc. and Eco-Stim Energy Solutions. Mr. Snyder currently serves as a trustee for non-profit organizations BRC (Bowery Residents Committee) and Shining Hope for Communities. Mr. Snyder received a B.A. from Wesleyan University and a J.D. from the University of Pennsylvania Law School.

The Board believes that Mr. Snyder's extensive financial expertise and experience in representing public and private companies in complex financial transactions brings important experience and skill to the Board.

Delinquent Section 16(a) Reports

Section 16(a) of the Exchange Act requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC initial reports of ownership and reports of changes in ownership of our common stock, $0.01 per share ("Common Stock"), and other equity securities.

To our knowledge, based solely on a review of Form 3, Form 4 and Form 5 (including amendments) filed electronically with the SEC and written representations made to us that no other reports were required, during the fiscal year ended December 31, 2024, all Section 16(a) filing requirements applicable to our officers, directors and greater than 10% beneficial owners of our capital stock were complied with.

Code of Business Conduct and Ethics

The Company has adopted a Code of Business Conduct and Ethics (the "Code of Ethics"), which applies to employees, officers and directors of the Company. The Code of Ethics can be found on the Company's website located at https://www.amplifyenergy.com/investor-relations/corporate-governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Insider Trading Policy

We have adopted an Insider Trading Policy (the "Insider Trading Policy") governing the purchase, sale and/or other dispositions of our securities by our directors, officers and employees and by us that is reasonably designed to promote compliance with insider trading laws, rules, and regulations, and the listing standards of the New York Stock Exchange. A copy of the Insider Trading Policy is filed as an exhibit to this Form 10-K/A.

Audit Committee Members and Financial Expert

The current members of the Audit Committee of the Board (the "Audit Committee") are Mr. Snyder (Chair) and Mses. Douglas and Prasad. Independent non-employee director Randal T. Klein served as a member of the Audit Committee during 2024 and until his departure from the Board on May 15, 2024. Messers. Klein and Snyder and Mses. Douglas and Prasad each were independent under the standards set forth by the NYSE applicable to members of the Audit Committee during their terms of service on the Audit Committee. The Audit Committee held 4 meetings during 2024.

The Audit Committee assists the Board by overseeing responsibilities regarding the integrity of the Company's financial statements, the Company's compliance with legal and regulatory requirements, the qualifications, independence and performance of the Company's independent registered public accounting firm and the effectiveness and performance of the Company's internal audit function.

The Board evaluates each of the members of the Audit Committee for financial literacy and the attributes of a financial expert at least annually, and most recently on March 20, 2025. The Board determined that each of the Audit Committee members is financially literate and that independent director Mr. Snyder is an audit committee financial expert as defined by the SEC.

ITEM 11. EXECUTIVE COMPENSATION

We are currently considered a "smaller reporting company" within the meaning of the Exchange Act for purposes of the SEC's executive compensation disclosure rules. Accordingly, we have provided disclosures relating to our "Named Executive Officers" or "NEOs," which are the individuals who served as principal executive officer and the next two most highly compensated executive officers for the fiscal year ended December 31, 2024.

Name	Position with the Company
Martyn Willsher	President and Chief Executive Officer
Daniel Furbee	Senior Vice President & Chief Operating Officer
Eric M. Willis	Senior Vice President, General Counsel & Corporate Secretary

2024 Summary Compensation Table

The following table includes the compensation earned by our NEOs for the fiscal years ended December 31, 2024 and 2023.

Name and Principal Position	Year	Salary (\$)(1)	Bonus (\$)(2)	Stock Awards (\$)(3)	Non-equity Incentive Plan Compensation (\$)(4)	All Other Compensation (\$)(5)	Total (\$)
Martyn Willsher	2024	539,885	27,040	1,355,922	540,800	20,700	2,484,347
President and Chief Executive Officer	2023	517,692	127,920	1,344,002	392,080	19,800	2,401,494
Daniel Furbee	2024	397,046	16,000	684,172	320,000	20,700	1,437,918
Senior Vice President & Chief Operating Officer	2023	280,000	62,681	985,940	192,119	15,960	1,536,700
Eric M. Willis(6) Senior Vice President, General Counsel & Corporate Secretary	2024	378,380	200,750	746,644	264,992	20,700	1,611,466

(1) The amounts in this column represent the base salary earned by each of our NEOs in the applicable fiscal year. Mr. Furbee joined the Company on March 17, 2023, and therefore the amount reported in 2023 reflects the annual base salary he earned for the portion of 2023 that he was employed by the Company.

(2) The amounts in this column represent, for fiscal year 2024, (i) a discretionary cash incentive bonus awarded to each of our NEOs in respect of fiscal year 2024, and (ii) for Mr. Willis, this number also includes the cash portion of the Merit Bonus (as defined below) (i.e., \$187,500). See the section below titled "Annual Incentive Bonuses" for more information on such bonuses.

(3) The amounts in this column represent the aggregate grant date fair value of the stock awards granted to our NEOs in the applicable fiscal year, computed in accordance with FASB ASC Topic 718, but excluding any impact of estimated forfeiture rates. For fiscal year 2024, our NEOs received a grant under the EIP (as defined below) of restricted stock units with both performance- and service-based vesting conditions ("PSUs") and restricted stock units with only service-based vesting conditions ("RSUs"). For fiscal year 2024, this number also includes, for Mr. Willis, the equity portion of the Merit Bonus (i.e., 10,258 RSUs). The amounts reported in this column in respect of the PSU awards granted to our NEOs reflect the Company's determination of the probable outcome of the performance-vesting conditions. Assuming maximum performance for the PSU awards granted to our NEOs in fiscal year 2024, the grant date fair value included in this column for Messrs. Willsher, Furbee and Willis would be equal to approximately \$1,880,266, \$822,620 and \$822,620, respectively. See the section below titled "Long Term Incentive Compensation" for more information.

(4) The amounts in this column reflect the annual incentive bonuses paid in cash to each NEO pursuant to our annual incentive bonus program based on the achievement of the applicable performance conditions. See the section below titled "Annual Incentive Bonuses" for more information.

(5) Amounts in this column reflect, for fiscal year 2024, Company contributions to the Company's 401(k) plan.

(6) Mr. Willis was not an NEO in fiscal year 2023.

Narrative Disclosure to Summary Compensation Table

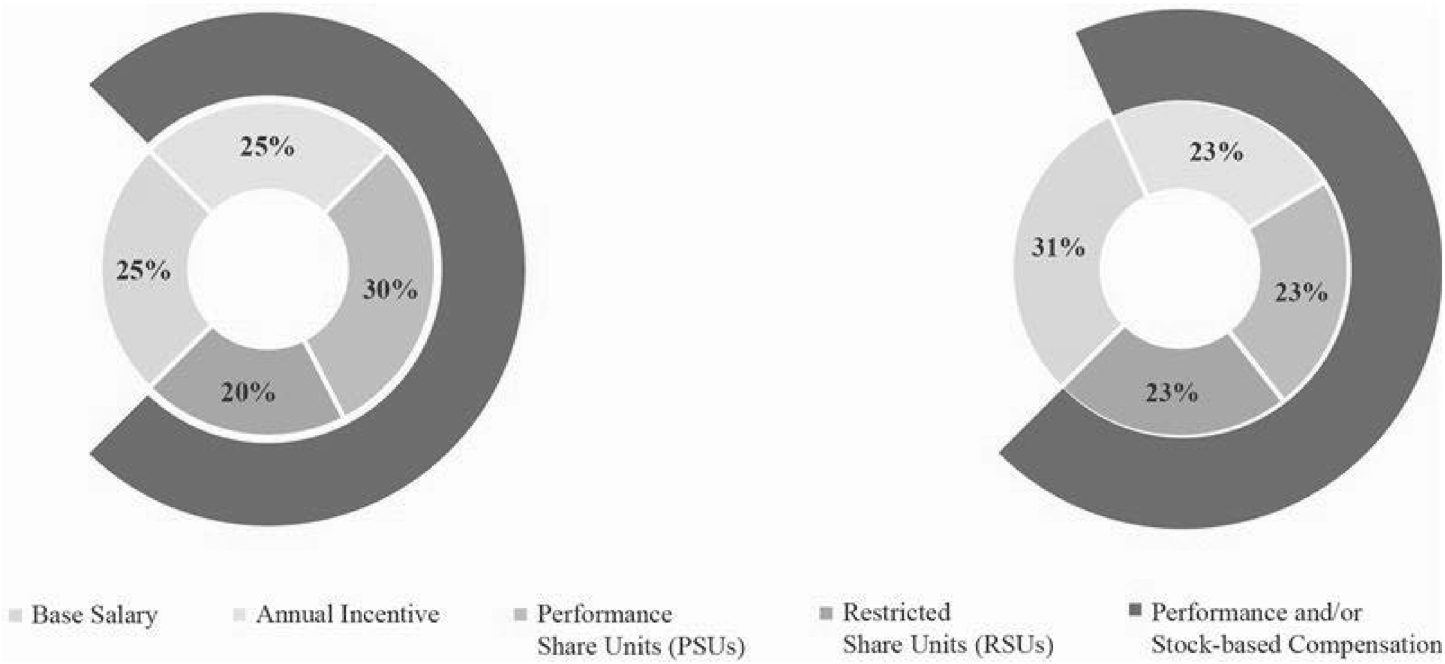
The Company employs a compensation philosophy that emphasizes pay-for-performance based on a combination of Company and individual performance, and places the majority of each officer's compensation at risk based on key performance indicators or stock price performance over the long term. We believe this pay-for-performance approach generally aligns the interests of our executive officers with that of our stockholders. The Company's executive compensation program is designed to attract and retain individuals with the background and skills necessary to successfully execute on our business strategy in a demanding environment, to motivate those individuals to reach near-term and long-term goals and to reward success in achieving such goals. As our needs evolve and as circumstances require, we periodically reevaluate our executive compensation philosophy, principal objectives and programs. Certain best practice elements of our compensation program are described below.

What We Do	What We Do Not Do
✓ Award majority of NEO compensation as performance-based, at-risk compensation	✗ No excessive perquisites
✓ Cap maximum payout opportunities for short- and long-term incentive compensation	✗ No excise tax gross-ups upon a change of control
✓ Majority of annual incentive goals tied to quantitative metrics	✗ No hedging of Company stock permitted
✓ Cap PSU payouts at target if Amplify's total shareholder return ("TSR") is negative over the performance period	✗ No single-trigger change-in-control benefits
✓ Maintain a clawback policy in the event of a financial restatement	
✓ Maintain robust stock ownership guidelines	
✓ Maintain anti-hedging and anti-pledging policies	
✓ Engage an independent, external compensation consultant	

Our compensation program is designed to align executive compensation with Company performance. The following charts illustrate that the largest component of target compensation for our NEOs is performance-based, aligning the interests of our NEOs with those of our stockholders. For our CEO and our other NEOs, 75% and 69% of the total target compensation for fiscal year 2024 was allocated to performance and/or stock-based compensation, respectively. The chart below reflects the target compensation for our NEOs' during fiscal year 2024, including base salary, target annual incentive bonus and target long-term incentive opportunities.

FISCAL YEAR 2024 TARGET COMPENSATION (AS OF DECEMBER 31, 2024)

Chief Executive Officer **Other Named Executive Officers**



Determining Compensation

To understand the competitive market for executive talent, the Compensation Committee of the Board (the "Compensation Committee"), in consultation with its independent compensation consultant, Meridian Compensation Partners, LLC ("Meridian"), compares Amplify's compensation design and pay levels to compensation data for similarly situated executives at peer companies. The Compensation Committee, in consultation with Meridian, then selects peer companies based on their industry and company size as defined by enterprise value, market capitalization, assets, and production.

Compensation Peer Group

As a result of the recent consolidation in the exploration and production (E&P) sector, compensation peer group selection for smaller E&P companies is challenging, with a limited number of companies that have a similar size and operations to Amplify. The Compensation Committee developed a peer group for its fiscal year 2024 compensation decisions with the assistance of Meridian. The Compensation Committee, in consultation with Meridian, approved the following peer group of 10 companies for purposes of assessing fiscal year 2024 executive compensation:

2024 Compensation Peer Group		
Berry Corporation	Granite Ridge Resources, Inc.	SilverBow Resources, Inc.
Diversified Energy Company PLC	Riley Exploration Permian, Inc.	VAALCO Energy, Inc.
Evolution Petroleum Corporation	Ring Energy, Inc.	W&T Offshore, Inc.
Gran Tierra Energy Inc.	SandRidge Energy, Inc.	

Performance Peer Group

Amplify has historically used the same peer group for executive compensation and relative TSR performance measurement purposes. However, for fiscal year 2024, in light of transactional activity involving exploration and production companies of comparable size to Amplify and the corresponding reduction in the number of relevant peers, the Compensation Committee, with the assistance of Meridian, evaluated the utilization of a separate peer group to measure relative Company performance as part of its long-term incentive program.

For purposes of determining this performance peer group, the Compensation Committee approved the inclusion of two industry specific, market-based indices to ensure a robust comparator set to buffer against continued transactional activity over the performance period and to acknowledge the broader competition for investor capital. The Compensation Committee, in consultation with Meridian, approved the following peer group of 11 companies and 2 broader indices to assess fiscal year 2024 long-term incentive performance:

2024 Performance Peer Group

Berry Corporation	Ring Energy, Inc.	W&T Offshore, Inc.
Diversified Energy Company PLC	SandRidge Energy, Inc.	SPDR S&P Oil & Gas Exploration & Production ETF
Gran Tierra Energy Inc.	SilverBow Resources, Inc.	iShares Russell 2000 ETF
Mach Natural Resources LP	TXO Partners L.P.	
Riley Exploration Permian, Inc.	VAALCO Energy, Inc.	

The Compensation Committee works with Meridian to determine our NEO's compensation generally, which it then recommends to the Board for approval.

Base Salaries

In fiscal year 2024, the Company provided base salaries for our NEOs that were generally competitive within the market, but relatively moderate as compared to the base salaries paid by companies with which we compete for similar executive talent across the broad spectrum of the energy industry. Following the Compensation Committee's discussions with Meridian, and in order to be more competitive with industry peers, the Board approved increases to our NEOs' base salaries for fiscal year 2024, effective as of January 25, 2024.

The annualized base salaries paid to our NEOs in fiscal years 2024 and 2023 are set forth in the chart below:

Name	2023	2024	Percent Increase (2023-2024)
Mr. Willsher	$ 520,000	$ 540,800	4.0 %
Mr. Furbee	$ 364,000	$ 400,000	9.9 %
Mr. Willis	$ 364,000	$ 378,560	4.0 %

Annual Incentive Bonuses

Annual incentive cash bonuses represent the short-term performance-based element of the Company's compensation program. Annual incentive bonus awards may be earned pursuant to our annual incentive bonus program and are based on achievement of pre-determined Company financial objectives, as determined by the Board. We review overall contribution to Company performance for our NEOs annually to determine the annual incentive bonus award payments for the most recently completed fiscal year. At the end of each fiscal year, we meet with each NEO to discuss our performance goals for the upcoming fiscal year and what each NEO is expected to contribute to help us achieve those performance goals.

Generally, the determination of each NEO's actual annual bonus payout will reflect actual corporate performance measured against pre-determined performance goals, subject to the Compensation Committee's discretion to adjust payments as it deems appropriate.

2024 Annual Incentive Bonus

The Compensation Committee considers several factors in determining the total bonus opportunity for our NEOs pursuant to our annual incentive bonus program. For fiscal year 2024, the Company adopted revised annual incentive bonus metrics and methodologies (as compared to fiscal year 2023). As part of the Company's effort to bring annual bonus metrics further in line with our industry peers, for fiscal year 2024 the Compensation Committee increased the weighting of the quantitative metrics to 100% and eliminated the weighted discretionary component.

With significant focus placed on the Company's 2024 development plan at our producing oil property located in federal waters offshore Southern California ("Beta"), the Compensation Committee determined to bifurcate the oil and natural gas production metrics to better align with Beta's 100% oil production profile. The Compensation Committee also placed greater emphasis on the Company's key financial metrics, increasing the weighting of (i) reported free cash flow from 15% to 30% and (ii) lease operating expense and capital expenditure from 10% to 20%. The Compensation Committee retains all powers and discretion necessary or appropriate to administer the Company's annual incentive bonus program and to control its operation.

For the 2024 fiscal year, the Company's performance measures in respect of the annual incentive bonus program were the following:

Performance Metric	Weight
Reported free cash flow ($MM)	30 %
Average daily production (oil) (Mboe/d)	20 %
Average daily production (natural gas / NGLs) (Mboe/d)	5 %
Lease operating expense and capital expenditures ($MM)	20 %
Cash general and administrative expense ($MM)	10 %
ESG - Total recordable incident rate (3-year average improvement)	5 %
ESG - Spill rate (3-year average improvement)	5 %
ESG - Strategy (%)	5 %
Total	**100 %**

Target performance levels for each performance objective above were established by the Compensation Committee in the first quarter of fiscal year 2024, and were set at challenging levels that were both consistent with our long-term goals and intended to incentivize and reward superior performance. In addition, a threshold level of performance was established for each performance objective, and if threshold performance for a performance objective was not achieved, no bonus amount will be earned in respect of such performance objective.

For fiscal year 2024, the pre-determined performance goals, and the Company's actual performance with respect to such goals, were as follows:

Performance Metric	Threshold	Target	Maximum	Weight	Actual Performance
Reported free cash flow ($MM)	$ 10.0	$ 24.3	$ 38.6	30 %	31.3 %
Average daily production (oil) (Mboe/d)	6.8	8.5	10.2	20 %	19.1 %
Average daily production (natural gas / NGLs) (Mboe/d)	9.2	11.5	13.7	5 %	4.7 %
Lease operating expense and capital expenditures ($MM)	$ 220.0	$ 196.0	$ 172.0	20 %	14.9 %
Cash general and administrative expense ($MM)	$ 30.0	$ 27.0	$ 24.0	10 %	10.2 %
ESG – Total recordable incident rate (3-year average improvement) (#)	1.9	1.1	0.3	5 %	7.2 %
ESG – Spill rate (3-year average improvement) (#)	33.0	22.0	11.0	5 %	7.1 %
ESG – Strategy (%)	—	5 %	—	5 %	5.0 %

In evaluating the Company's performance for fiscal year 2024, the Compensation Committee considered many factors, including the strong financial performance of the organization and the progress of various strategic and operational objectives, including, but not limited to, (i) the pending merger with Juniper Capital Advisors, L.P., (ii) the strong performance of the Beta development plan, (iii) the successful renegotiation of the sinking fund payments, which resulted in a reduction of approximately $7 million per year, (iv) the monetization of certain East Texas acreage with Haynesville deep rights and (v) the reduction of the Company's suspense liability by approximately $8.4 million. The Committee also recognized the achievements related to the Company's ESG strategy, including (i) the completion of the emissions reduction and electrification facility projects, (ii) the significant reductions in both total recordable incident rate and spill rate, (iii) the publication of the Company's second annual sustainability report and (iv) the inclusion of additional metrics to improve and reinforce the Company's safety culture.

Based on the Compensation Committee's evaluation of the Company's overall performance for fiscal year 2024, the Compensation Committee determined that such performance resulted in a payout for each NEO of 99.5% of target. The Compensation Committee then exercised its upward discretion pursuant to the Company's annual incentive bonus program to payout an additional 5.5% bonus to each of our NEOs.

Beta One-Time Merit Bonus

In February 2024, Mr. Willis received a one-time merit bonus payment in consideration for his contributions to the Company in connection with the oil incident at Beta in 2021, which was paid in the form of cash and equity (the "Merit Bonus"). The cash portion of the Merit Bonus was equal to $187,500, and the equity portion of the Merit Bonus was paid as a grant of 10,258 RSUs, which vest on an equal basis over a three-year period and so long as Mr. Willis remains employed by the Company through the applicable vesting date.

Employment Agreements

Each of our NEOs are party to an employment agreement with the Company and Amplify Energy Services LLC, effective as of November 1, 2023 (collectively, the "Employment Agreements"). The Employment Agreements memorialize each NEO's initial base salary and target annual bonus. Each Employment Agreement subjects the NEO to certain non-competition, non-solicitation and non-interference covenants that apply during the term of employment and for 12 months thereafter, as well as perpetual assignment of inventions, non-disparagement and confidentiality covenants. See the section below titled "Potential Payments upon Termination or Change in Control-Severance Benefits under Employment Agreements" for further details regarding the payments that our NEOs are eligible to receive upon a termination of employment or a change in control.

Long Term Incentive Compensation

The long-term incentive equity awards granted to our NEOs in fiscal year 2024 were made under the Amplify Energy Corp. Equity Incentive Plan (the "2021 EIP"), which permitted us to grant nonqualified stock options, incentive stock options, restricted stock awards, RSUs, PSUs, stock appreciation rights, other stock-based awards and cash awards. On April 1, 2024, we adopted the Amplify Energy Corp. 2024 Equity Incentive Plan, which superseded and replaced the 2021 EIP in its entirety upon its approval by our stockholders at the Company's fiscal year 2024 annual meeting (the "2024 EIP", and together with the 2021 EIP, collectively, the "EIP"). The purpose of the EIP is to align the interests of our eligible service providers with the interests of our stockholders by providing long term incentive compensation awards tied to Company performance.

Each of our NEOs is eligible to participate in the EIP. The EIP allows the Company to grant nonqualified stock options, incentive stock options, restricted stock, RSUs, PSUs, stock appreciation rights, other stock-based awards and cash awards. The Compensation Committee determines the size and vesting terms of all awards granted under the EIP and recommends such terms to the Board for approval. The Compensation Committee administers all other aspects of the EIP.

For fiscal year 2024, each of our NEOs received an annual grant of PSUs and RSUs, with PSUs representing 50% of the total award value (or 60% for Mr. Willsher) and RSUs representing the remaining 50% of the total award value (or 40% for Mr. Willsher). Mr. Willsher's allocations differ from that of the other NEOs due to the Company's efforts to strengthen the alignment of pay and performance. Commencing with fiscal year 2025, Mr. Willsher's long-term incentive package was increased from 200% of base salary to 260% of base salary, with additional weighting to performance-based compensation (70% PSUs, 30% RSUs).

The PSUs granted to our NEOs in fiscal year 2024 vest based on the achievement of the Company's relative total shareholder return, measured during the three-year performance period, subject to continued employment through the applicable vesting date. If the Company's absolute shareholder return is negative over such performance period, the PSU payout will be capped at 100% of target.

The RSUs granted to our NEOs in fiscal year 2024 vest ratably over a three-year period, subject to continued employment through each applicable vesting date.

See the section below titled "Potential Payments upon Termination or Change in Control-Accelerated Vesting under Award Agreements" for details regarding the payments that our NEOs are eligible to receive pursuant to the EIP and their applicable award agreements upon certain terminations of employment or a change in control.

Clawback Policy

The Compensation Committee has adopted a clawback policy (the "Clawback Policy") that complies with NYSE's new clawback rules promulgated under Section 10D of the Exchange Act. In the event the Company is required to prepare an accounting restatement of its financial statements due to the Company's material noncompliance with any such financial reporting requirement, the Clawback Policy requires that covered executives must reimburse the Company, or forfeit, any excess incentive-based compensation "received" (as defined under Section 10D of the Exchange Act) by such covered executive during the three completed fiscal years immediately preceding the date on which the Company is required to prepare the restatement. Executives covered by the Clawback Policy are current and former executive officers, as determined by the Compensation Committee in accordance with Section 10D of the Exchange Act and the NYSE listing standards. Incentive-based compensation subject to the Clawback Policy includes any cash or equity compensation that is granted, earned or vested based wholly or in part on the attainment of a financial reporting measure. The amount subject to recovery is the excess of the incentive-based compensation received based on the erroneous data over the incentive-based compensation that would have been received had it been based on the restated results. The Clawback Policy will only apply to incentive-based compensation received on or after October 2, 2023. The Clawback Policy is available as Exhibit 97.1 to the Company's Annual Report on Form 10-K for the year-ended December 31, 2024.

Equity Award Granting Practices

We do not currently grant new awards of stock options, stock appreciation rights or similar option-like instruments. Accordingly, we do not have a specific policy or practice on the timing of such awards in relation to the disclosure of material nonpublic information by the Company. In the event we determine to grant such awards in the future, the Board and the Compensation Committee will evaluate the appropriate steps to take in relation to the foregoing.

Outstanding Equity Awards at 2024 Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards held by our NEOs as of December 31, 2024.

Name	Grant Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)[1]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)[1]
Martyn Willsher	2/1/2024[2]	—	—	102,411	614,466
	2/1/2024[4]	68,274	409,644		
	2/1/2023[2]	—	—	56,117	336,702
	2/1/2023[4]	37,412	224,472	—	—
	2/1/2022[3]	—	—	120,192	721,152
	2/1/2022[4]	20,032	120,192	—	—
Daniel Furbee	2/1/2024[2]	—	—	44,805	268,830
	2/1/2024[4]	44,805	268,830	—	—
	4/1/2023[2]	—	—	55,829	334,974
	4/1/2023[4]	37,220	223,320	—	—
Eric M. Willis	2/1/2024[2]	—	—	44,805	268,830
	2/1/2024[4]	55,063	330,378		
	2/1/2023[2]	—	—	29,462	176,772
	2/1/2023[4]	19,642	117,852	—	—
	2/1/2022[3]	—	—	72,116	432,696
	2/1/2022[4]	12,020	72,120		

(1) Amounts reported in this column are based on the fair market value of our common stock as of December 31, 2024, the last day of fiscal year 2024 (i.e., $6.00 per share).

(2) Reflects PSUs that were granted to our NEOs under the EIP, and cliff vest pursuant to the Company's achievement of certain performance goals over a three-year performance period, subject to the holder's continued employment by the Company through the settlement date. As of December 31, 2024, the Company's achievement of the performance goals was at (i) 100% of target for PSU awards granted in fiscal year 2023 and (ii) at 83% of target for PSU awards granted in fiscal year 2024. Accordingly, the number of PSUs reported in the table reflect amounts based on target performance (100% of target) for the 2023 PSU awards and target performance (100% of target) for the 2024 PSU awards.

(3) Reflects PSUs that were granted to our NEOs under the EIP, and cliff vest pursuant to the Company's achievement of certain performance goals over a three-year performance period, subject to the holder's continued employment by the Company through the settlement date. In January 2024, the Compensation Committee certified the level of performance achievement with respect to the PSU awards relating to the performance period ended December 31, 2024. Accordingly, such PSU awards are reported based on actual achievement, which was 200% of target.

(4) Reflects RSUs that were granted to our NEOs under the EIP. These RSUs vest in substantially equal installments on each of the first three anniversaries of the grant date, so long as the holder remains employed by the Company through the applicable vesting date.

Potential Payments upon Termination or Change of Control

The following table sets forth information concerning the payments to be made to each of our NEOs in connection with a change of control or termination of employment, presuming a termination or change of control date of December 31, 2024 and the fair market value of a share of common stock on December 31, 2024 ($6.00 per share). The below table only includes information for employment termination or change of control events that trigger vesting or severance-related payments and assumes that each executive will take all action necessary or appropriate for such person to receive the maximum available benefit, such as execution of a release of claims. The precise amount that each of our NEOs would receive cannot be determined with any certainty until a change of control has occurred.

Name	Involuntary Termination (Non-Change in Control) ($)(1)(2)	Termination upon Death or Disability ($)(3)	Involuntary Termination in Connection with a Change in Control ($)(4)(5)
Martyn Willsher			
Cash Severance	1,622,400	540,800	2,704,000
Accelerated Equity Compensation	1,904,754	—	2,426,628
Health and Welfare Benefits	31,839	—	31,839
Total	3,558,993	540,800	5,162,467
Daniel Furbee			
Cash Severance	1,120,000	320,000	1,760,000
Accelerated Equity Compensation	805,080	—	1,095,954
Health and Welfare Benefits	31,839	—	31,839
Total	1,956,919	320,000	2,887,793
Eric M. Willis			
Cash Severance	1,022,112	264,992	1,552,096
Accelerated Equity Compensation	1,160,508	—	1,398,648
Health and Welfare Benefits	7,992	—	7,992
Total	2,190,612	264,992	2,958,736

(1) If Messrs. Willsher, Furbee and Willis experience a Good Leaver Termination (as defined below) (not in connection with a change in control) described below, then subject to the NEO's execution and non-revocation of a general release of claims and continued compliance with the restrictive covenants, the NEO will be entitled to: (i) the Prior Year Bonus (as defined below), if any, (ii) the Pro Rata Bonus Amount (as defined below), if any, (iii) an amount equal to two times the annual base salary as in effect on the day before the termination date, payable in a lump sum within 70 days following the termination date and (iv) up to 12 months of continued health insurance benefits under the Company group health plan (at the employee rate), subject to the NEO's continued eligibility for COBRA coverage and terminable if the NEO obtains other employment offering group health plan coverage.

(2) Accelerated Equity Compensation amounts reflect market value of outstanding RSUs, which would become vested in connection with a Good Leaver Termination. In the event of a Good Leaver Termination, subject to the NEO's execution and non-revocation of a release of claims and continued compliance with the restrictive covenants, any unvested RSUs will fully vest and a pro-rata portion of any unvested PSUs will vest based on actual performance through the end of the applicable performance period to occur immediately following the date of termination. The values included in the table for the pro-rata portion of unvested PSUs reflect 200% of target for the 2022 PSUs, 100% of target for the 2023 PSUs, and 100% of target for the 2024 PSUs.

(3) If an NEO's employment is terminated by us while the NEO is disabled, or if the NEO's employment terminates as a result of the NEO's death, subject to the NEO's execution and non-revocation of a release of claims and continued compliance with the restrictive covenants, as applicable, each NEO is entitled to (i) the Prior Year Bonus and (ii) the Pro Rata Bonus Amount.

(4) If Messrs. Willsher, Furbee and Willis experience a Good Leaver Termination within the 18-month period following a change of control (as defined in the Employment Agreement), then subject to the NEO's execution and non-revocation of a release of claims and continued compliance with the restrictive covenants, the NEO will be entitled to: (i) the Prior Year Bonus, if any, (ii) the Pro Rata Bonus Amount, if any, (iii) an amount equal to two times the sum of (x) the annual base salary as in effect on the day before the termination date, and (y) the target annual bonus, payable in a lump sum within 70 days following the termination date and (iv) up to 12 months of continued health insurance benefits under the Company group health plan (at the employee rate), subject to the NEO's continued eligibility for COBRA coverage and terminable if the NEO obtains other employment offering group health plan coverage.

(5) In the event an NEO experiences a Good Leaver Termination during the 18-month period following a change in control (a "Qualifying CIC Termination"), any unvested RSUs fully vest and each incomplete performance period with respect to unvested PSUs will be deemed to have ended as of the third business day prior to the date of the consummation of such change in control (the "Measurement Date") and a number of unvested PSUs will vest equal to the greater of (A) the number of PSUs that would vest based on actual performance through the Measurement Date and (B) the number of PSUs that would vest based on target performance, as set forth in the applicable award agreement. In the event an NEO experiences a Qualifying CIC Termination following a change in control occurring December 31, 2024, our NEOs will be entitled to the amounts set forth in "Accelerated Equity Compensation" pursuant to accelerated vesting of their RSUs and PSUs under the applicable award agreements, assuming performance at 200% of target for the 2022 PSUs, 100% of target for the 2023 PSUs and 100% of target for the 2024 PSUs.

Severance Benefits under Employment Agreements

Under the Employment Agreements, upon any termination of employment with the Company, Messrs. Willsher, Frew and Furbee will be entitled to (i) accrued but unpaid base salary through the termination date, (ii) any unreimbursed business expenses incurred through the termination date and (iii) payment of any amounts accrued and vested under any employee benefit plans or programs of the Company, and any payments or benefits required to be made or provided under applicable law (collectively, the "Accrued Amounts").

In the event of a termination of the NEO's employment with the Company without "cause" (as defined below) or for "good reason" (as defined below) (each, a "Good Leaver Termination"), then in addition to the Accrued Amounts and subject to the NEO's execution and non-revocation of a release of claims and continued compliance with the restrictive covenants, the NEO will be entitled to: (i) any unpaid annual bonus with respect to the calendar year ending on or preceding the termination date, in an amount equal to the annual bonus amount the NEO would have received (if any) had the NEO been employed on the payment date, payable at the same time annual bonuses are paid to actively employed senior executives of the Company (the "Prior Year Bonus"), (ii) a pro rata portion of the target Annual Bonus for the calendar year in which the termination occurs (the "Pro Rata Bonus Amount"), payable in a lump sum within 70 days following the termination date, (iii) an amount equal to two times the NEO's annual base salary as in effect on the day before the termination date, payable in a lump sum within 70 days following the termination date and (iv) up to 12 months of continued health insurance benefits under the Company group health plan (at the employee rate), subject to the NEO's continued eligibility for COBRA coverage and terminable if the NEO obtains other employment offering group health plan coverage.

If an NEO's employment with the Company is terminated due to death or "disability" (as defined in the Employment Agreements), then in addition to the Accrued Amounts and subject to the NEO's execution and non-revocation of a general release of claims and continued compliance with the restrictive covenants, as applicable, the NEO is entitled to: (i) the Prior Year Bonus and (ii) the Pro Rata Bonus Amount.

In the event of a termination of the NEO's employment with the Company without "cause" or for "good reason" within the 18-month period following a change of control (as defined in the Employment Agreement), then in addition to the Accrued Amounts and subject to the NEO's execution and non-revocation of a general release of claims and continued compliance with the restrictive covenants, the NEO will be entitled to: (i) the Prior Year Bonus, if any, (ii) the Pro Rata Bonus Amount, if any, (iii) an amount equal to two times the sum of (x) the NEO's annual base salary as in effect on the day before the termination date, and (y) the target annual bonus, payable in a lump sum within 70 days following the termination date and (iv) up to 12 months of continued health insurance benefits under the Company group health plan (at the employee rate), subject to the NEO's continued eligibility for COBRA coverage and terminable if the NEO obtains other employment offering group health plan coverage.

The Employment Agreements provide for a Section 280G of the Internal Revenue Code of 1986, as amended (the "Code"), "best-net" cutback, which would cause an automatic reduction in any payments or benefits the NEOs would receive that constitute parachute payments within the meaning of Section 280G of the Code, in the event such reduction would result in the NEOs receiving greater payments and benefits on an after-tax basis.

For purposes of the Employment Agreements, "cause" generally means the occurrence of the NEO's: (i) conviction of a felony, or plea of guilty or nolo contendere to, any felony or any crime of moral turpitude, (ii) repeated intoxication by alcohol or drugs during the performance of the NEO's duties, (iii) embezzlement or other willful and intentional misuse of any of the funds of the Company or its direct or indirect subsidiaries, (iv) commission of a demonstrable act of fraud, (v) willful and material misrepresentation or concealment on any written reports submitted to the Company or its direct or indirect subsidiaries, (vi) material breach of the Employment Agreement or any other agreement with the Company, (vii) failure to follow or comply with the reasonable, material and lawful written directives of the Board or (viii) conduct constituting a material breach of the Company's then-current code of conduct or other similar written policy that has been provided to the NEO.

For purposes of the Employment Agreement, "good reason" generally means the occurrence of any of the following without the NEO's written consent: (i) a relocation of the NEO's principal work location to a location in excess of 40 miles from its then current location (provided that, a relocation shall not include: (A) the NEO's travel for business in the course of performing the NEO's duties for the Company, (B) the NEO working remotely or (C) the Company requiring the NEO to report to the office within the NEO's principal place of employment (instead of working remotely)), (ii) a reduction in the NEO's then current base salary or target annual bonus, or both, (iii) a material breach of any provision of the Employment Agreement by the Company or (iv) any material reduction in the NEO's title, authority, duties, responsibilities or reporting relationship from those in effect as of the effective date of the Employment Agreement, except to the extent such reduction occurs in connection with the NEO's termination of employment for "cause" or due to the NEO's death or disability.

Accelerated Vesting under Award Agreements

Pursuant to the applicable RSU award agreement, in the event of a termination of the participant's service by the Company without "cause" or by the participant for "good reason," any unvested RSUs will vest. Pursuant to the applicable PSU agreement, in the event of a termination of the participant's service by the Company without "cause" or by the participant for "good reason," a pro-rata portion of any unvested PSUs will immediately accelerate and vest based on actual performance through the date of termination. In the event such termination occurs during the 18-month period immediately following a change in control, each incomplete performance period will be deemed to have ended as of the applicable measurement date and a number of unvested PSUs will immediately vest equal to the greater of (A) the number of PSUs that would vest based on actual performance through such measurement date and (B) the number of PSUs that would vest based on target performance (as set forth in the applicable award agreement).

Pay Versus Performance

As required by Section 953(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(v) of Regulation S-K, we are providing the following information about the relationship between 'compensation actually paid' to the Principal Executive Officer of the Company ("PEO") and to our other non-PEO NEOs and certain financial performance of the Company. Compensation actually paid, as determined under SEC requirements, does not reflect the actual amount of compensation earned by or paid to our NEOs during a covered year. For further information concerning the Company's pay-for-performance philosophy and how the Company aligns executive compensation with the Company's performance, refer to the section above titled "Narrative Disclosure to Summary Compensation Table."

Year	Summary Compensation Table Total for PEO ($)[1]	Compensation Actually Paid to PEO ($)[1][2]	Average Summary Compensation Table Total for Non-PEO NEOs ($)[3]	Average Compensation Actually Paid to Non-PEO NEOs ($)[3][2]	Value of Initial Fixed $100 Investment Based On: Total Shareholder Return ($)[4]	Net Income (Loss) (in Thousands) ($)[5]
2024	2,484,347	2,032,137 [6]	1,524,692	1,333,584 [6]	101.18	12,946
2023	2,401,494	995,765	1,522,280	1,255,976	67.46	392,750
2022	1,580,799	2,909,862	968,111	1,765,553	182.64	57,875

(1) The name of the PEO reflected in these columns for each of the applicable fiscal years is Martyn Willsher.

(2) In calculating the 'compensation actually paid' amounts reflected in these columns, the fair value or change in fair value, as applicable, of the equity award adjustments included in such calculations was computed in accordance with FASB ASC Topic 718. The valuation assumptions used to calculate such fair values did not materially differ from those disclosed at the time of grant.

(3) The names of each of the non-PEO NEOs reflected in these columns are (i) for fiscal year 2024, Daniel Furbee and Eric M. Willis, (ii) for fiscal year 2023, James Frew and Daniel Furbee, and (iii) for fiscal year 2022, Richard Smiley and Eric M. Willis.

(4) The Company TSR reflected in this column for each applicable fiscal year is calculated based on a fixed investment of $100 at the applicable measurement point on the same cumulative basis as is used in Item 201(e) of Regulation S-K.

(5) Represents the amount of net income (loss) reflected in the Company's audited GAAP financial statements for each applicable fiscal year.

(6) For fiscal year 2024, the 'compensation actually paid' to the PEO and the average 'compensation actually paid' to the non-PEO NEOs reflect each of the following adjustments made to the total compensation amounts reported in the Summary Compensation Table for fiscal year 2024, computed in accordance with Item 402(v) of Regulation S-K:

	PEO	Average Non-PEO NEOs
Total Compensation Reported in 2024 Summary Compensation Table	$ 2,484,347	$ 1,524,692
Less, Grant Date Fair Value of Stock & Option Awards Reported in the 2024 Summary Compensation Table	$ 1,355,922	$ (715,408)
Plus, Year-End Fair Value of Awards Granted in 2024 that are Outstanding and Unvested	$ 1,292,427	$ 685,823
Plus, Change in Fair Value of Awards Granted in Prior Years that are Outstanding and Unvested (From Prior Year-End to Year-End)	$ (523,468)	$ (203,583)
Plus, Vesting Date Fair Value of Awards Granted in 2024 that Vested in 2024	$ —	$ —
Plus, Change in Fair Value of Awards Granted in Prior Years that Vested in 2024 (From Prior Year-End to Vesting Date)	$ 134,753	$ 42,060
Less, Prior Year-End Fair Value of Awards Granted in Prior Years that Failed to Vest in 2024	$ —	$ —
Plus, Dollar Value of Dividends or other Earnings Paid on Stock & Option Awards in 2024 prior to Vesting (if not reflected in the fair value of such award or included in Total Compensation for 2024)	$ —	$ —
Total Adjustments	$ (452,210)	$ (191,108)
Compensation Actually Paid for Fiscal Year 2024	$ 2,032,137	$ 1,333,584

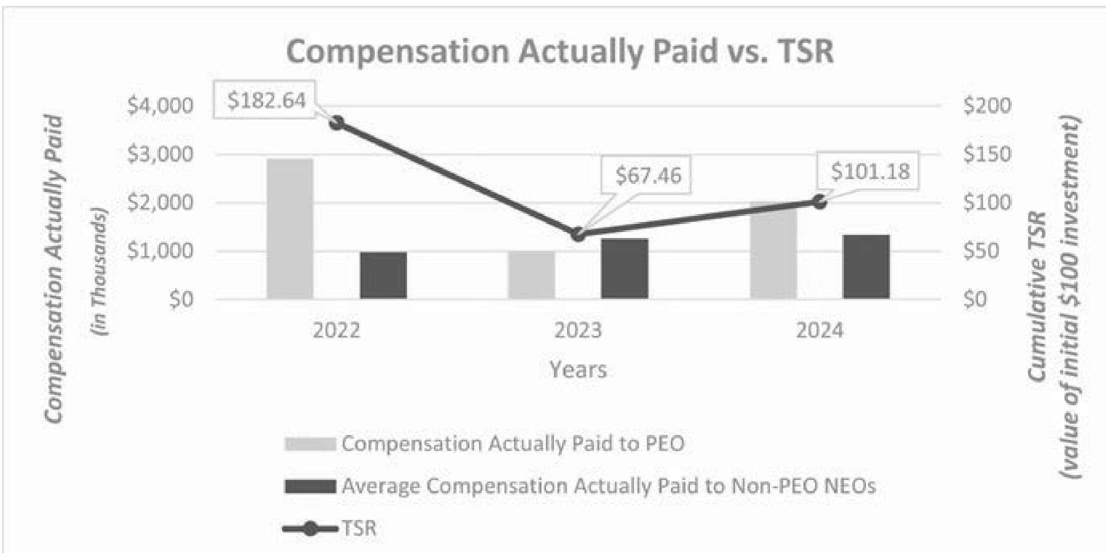
Pay versus Performance Comparative Disclosure

As described in more detail in the section titled "Narrative Disclosure to Summary Compensation Table," the Company's executive compensation program reflects a variable pay-for-performance philosophy. While the Company utilizes several performance measures to align executive compensation with Company performance, all of those Company measures are not presented in the table above. Further, the Company generally seeks to incentivize long-term performance, and therefore does not specifically align the Company's performance measures with 'compensation actually paid' for a particular year (as computed in accordance with Item 402(v) of Regulation S-K).

In accordance with Item 402(v) of Regulation S-K, the Company is providing the following descriptions of the relationships between the information presented in the table above.

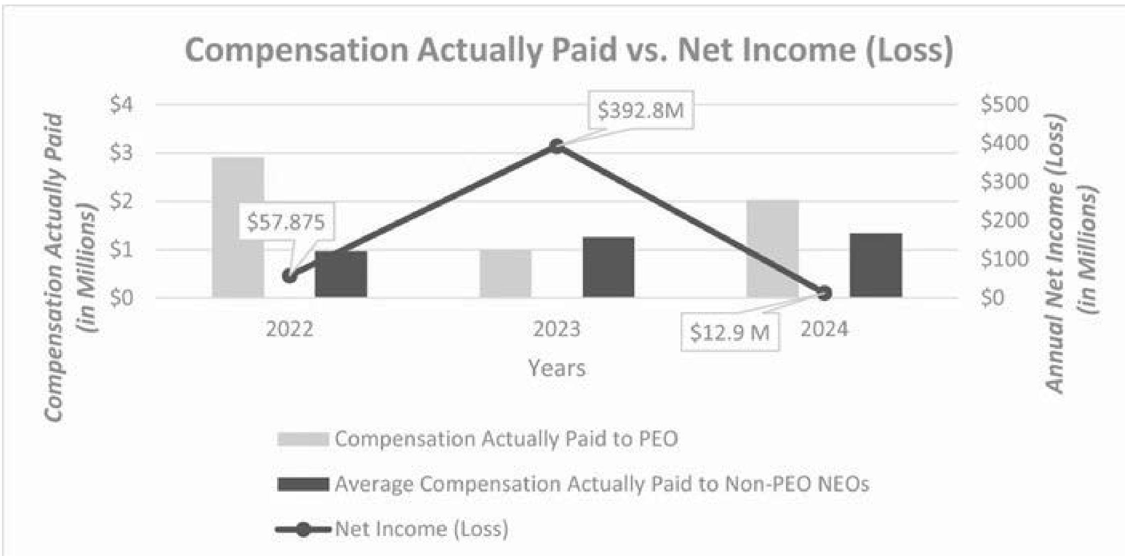
Compensation Actually Paid and Company TSR

As demonstrated by the following graph, the amount of 'compensation actually paid' to the PEO and the average amount of 'compensation actually paid' to the non-PEO NEOs is generally aligned with the Company's TSR over the three years presented in the table. This is because a significant portion of the 'compensation actually paid' to the PEO and to the non-PEO NEOs is comprised of equity awards.



Compensation Actually Paid and Net Income

The following graph illustrates the relationship between (x) the amount of ‘compensation actually paid’ to the PEO and the average amount of ‘compensation actually paid’ to the non-PEO NEOs and (y) the Company’s net income over the three years presented in the table. Compensation actually paid is less sensitive to our net income performance as compared to our TSR performance.



DIRECTOR COMPENSATION

Our director compensation policy provides for a combination of an annual cash retainer and equity award. Our non-employee directors' annual cash retainer for fiscal year 2024 was equal to $75,000 (or $175,000 for the Chairman of the Board), paid quarterly in advance. Our non-employee directors also received RSUs in fiscal year 2024 that fully vest over a one-year period, subject to continued service through such vesting date, each of which had a grant date fair value equal to $125,000 (or $175,000 for the Chairman of the Board). In addition, each of our non-employee directors who served as a committee chair received an additional $25,000 cash retainer.

Our non-employee directors are reimbursed for all out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director is fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

2024 Director Compensation Table

The following table presents information regarding compensation paid to our non-employee directors during the fiscal year ended December 31, 2024.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Total ($)
Deborah G. Adams	100,000	132,149	232,149
James E. Craddock	100,000	132,149	232,149
Patrice Douglas	75,000	132,149	207,149
Christopher W. Hamm	175,000	185,008	360,008
Randal T. Klein(3)	37,500	—	37,500
Vidisha Prasad	75,000	132,149	207,149
Todd R. Snyder	100,000	132,149	232,149

(1) Amounts in this column include the non-employee director's fiscal year 2024 annual cash retainer fee and, if applicable, the non-employee director's fiscal year 2024 committee chair fees.

(2) The amounts in this column represent the aggregate grant date fair value of the RSUs granted to our non-employee directors in fiscal year 2024, computed in accordance with FASB ASC Topic 718, but excluding any impact of estimated forfeiture rates. These RSUs vest on the first anniversary of the grant date, subject to the holder's continued service on the Board through the vesting date. As of December 31, 2024: (i) Mses. Adams, Douglas and Prasad and Messrs. Craddock and Snyder each held 19,665 unvested RSUs, and (ii) Mr. Hamm held 27,531 unvested RSUs.

(3) Effective as of May 15, 2024, Mr. Klein tendered his resignation from the Board.

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

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth, to our knowledge, as of April 17, 2025, the beneficial ownership of our Common Stock that are owned by:

- each person known by us to be a beneficial owner of more than 5% of our outstanding common shares;
- each director;
- each executive officer; and
- all executive officers and current directors as a group.

We have prepared the table and the related notes based on information provided in the most recent Section 16 filing or Schedule 13D filed by such person. We have not sought to verify such information. The number of shares beneficially owned by a person includes shares of Common Stock underlying warrants, stock options, restricted stock units, and any other derivative securities to acquire Common Stock held by that person that are currently exercisable or convertible within 60 days after the date of this Form 10-K/A. The shares issuable under any such securities are treated as outstanding for computing the percentage ownership of the person holding these securities, but are not treated as outstanding for the purposes of computing the percentage ownership of any other person.

Name of Beneficial Owner[1]	Shares of Common Stock Beneficially Owned[2]	Percentage of Outstanding[3]
BlackRock, Inc.[4]	2,515,369	6.2 %
Affiliates of Stoney Lonesome HF LP[5]	2,915,757	7.2 %
Dimensional Fund Advisors LP[6]	2,374,481	5.9 %
The Vanguard Group[7]	2,264,005	5.6 %
Deborah G. Adams	61,961	*
James E. Craddock	24,892	*
Patrice Douglas	60,295	*
Eric Dulany	34,617	*
Christopher W. Hamm	167,371	*
James Frew	54,222	*
Daniel Furbee	39,238	*
Anthony W. Lopez	140,421	*
Vidisha Prasad	13,185	*
Todd R. Snyder	108,416	*
Eric M. Willis	222,753	*
Martyn Willsher	310,794	*
All Executive Officers and Current Directors as a Group (12 persons)	1,238,165	3.1 %

* Less than 1.0%

(1) Unless otherwise noted, the address for all beneficial owners in this table is c/o Amplify Energy Corp., 500 Dallas Street, Suite 1700, Houston, Texas 77002.

(2) The amounts and percentages of Common Stock beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares voting power, which includes the power to vote or direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Under these rules, more than one person may be deemed to be a beneficial owner of the same securities, and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest.

(3) Based on 40,336,579 shares of Common Stock outstanding as of April 16, 2025. Shares of Common Stock (i) issuable upon the vesting of restricted stock units within 60 days of the date of this Form 10-K/A and (ii) subject to stock options that are currently exercisable or exercisable within 60 days of the date of this Form 10-K/A are deemed to be outstanding for the purpose of computing the percentage ownership of the person holding those restricted stock units or stock options, but are not treated as outstanding for the purpose of computing the percentage ownership of (x) any other person or (y) the aggregate held by all executive officers and directors as a group.

(4) Based on information contained in Amendment No. 1 to Schedule 13G filed with the SEC on January 29, 2024 by BlackRock, Inc. ("BlackRock") indicating that, as of September 30, 2024, Dimensional (as defined below) had sole voting power over 2,327,438 shares of Common Stock, shared voting power over 0 shares, sole dispositive power over 2,374,481 shares and shared dispositive power over 0 shares. The principal address of the foregoing entity is 50 Hudson Yards, New York, NY 10001.

(5) Based on information contained in Schedule 13D filed with the SEC on April 16, 2025 by a group consisting of Stoney Lonesome HF LP, The Drake Helix Holdings, LLC and Clint Coghill (together, "Stoney"), indicating that, as of April 15, 2025, Stoney was the beneficial owner of an aggregate of 2,915,757 shares of Common Stock. Mr. Coghill is the president of the general partner of Stoney Lonesome HF LP. The principal address of the foregoing persons is 222 S Riverside Plaza Ste 15-155, Chicago, IL 60606.

(6) Based on information contained in Schedule 13G filed with the SEC on October 31, 2024 by Dimensional Fund Advisors LP ("Dimensional") indicating that, as of December 31, 2023, BlackRock had sole voting power over 2,392,147 shares of Common Stock, shared voting power over 0 shares, sole dispositive power over 2,515,369 shares and shared dispositive power over 0 shares. The principal address of the foregoing entity is 6300 Bee Cave Road, Building One, Austin, TX 78746.

(7) Based on information contained in Amendment No. 1 to Schedule 13G filed with the SEC on February 13, 2024 by The Vanguard Group ("Vanguard") indicating that, as of December 31, 2023, Vanguard had sole voting power over 0 shares of Common Stock, shared voting power over 91,313 shares, sole dispositive power over 2,162,094 shares and shared dispositive power over 101,911 shares. The principal address of the foregoing entity is 101 Vanguard Blvd., Malvern, PA 19355.

Equity Compensation Plan Information

The following table summarizes information as of December 31, 2024 relating to our equity compensation plans pursuant to which grants of options, restricted stock or other rights to acquire shares may be granted from time to time.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Right	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)[1]	(b)	(c)[2][3]
Equity Compensation Plans Approved by our Security Holders	2,596,357	$ —	1,889,359
Equity Compensation Plans Not Approved by Our Security Holders	—	$ —	—
Total	2,596,357	$ —	1,889,359

(1) This column reflects all shares of Common Stock subject to outstanding equity awards granted under the 2021 EIP and the 2024 EIP. Such awards include the maximum number of shares of our common stock subject to outstanding RSUs and PSUs. Because the number of shares of our common stock to be issued upon settlement of PSUs is subject to performance-based vesting conditions, the number of shares of our common stock actually issued may be substantially less than the number reflected in column (a).

(2) No weighted average exercise price is included, as RSUs and PSUs do not have an exercise price.

(3) All securities reflected in this column (c) are shares of our common stock available under the 2024 EIP.

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

Procedures for Approval of Related Party Transactions

We maintain a policy for approval 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 exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A "Related Person" means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;
- any person who is known by us to be the beneficial owner of more than 5% of our Common Stock;
- any 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, executive officer, or a beneficial owner of more than 5% of our Common Stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer, or beneficial owner of more than 5% of our Common Stock; and
- any firm, corporation, or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10% or greater beneficial ownership interest.

The Audit Committee is charged with reviewing the material facts of all Related Party Transactions and either approving or disapproving of the Company's participation in such transactions under the Company's written policy regarding Related Party Transactions, which pre-approves or ratifies (as applicable) certain related person transactions, including:

- any employment by the Company of an executive officer if his or her compensation is required to be reported in the Company's proxy statement under Item 402;
- director compensation that is required to be reported in the Company's proxy statement under Item 402;
- any transaction with another company or which a Related Person's relationship is an employee (other than an executive officer), director or beneficial owner of less than 10% of that company's shares if the aggregate amount involved for any particular service does not exceed the greater of $500,000 or 25% of that company's total annual revenues; and
- charitable contribution, grant or endowment by the Company to a charitable organization, foundation or university at which a Related Person's only relationship is as an employee (other than an executive officer) or a director if the aggregate amount involved does not exceed the lesser of $200,000 or 10% of the charitable organization's total annual receipts.

In determining whether to approve or disapprove entry into a Related Party Transaction, the Audit Committee shall take into account, among other factors, the following: (i) 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, (ii) the extent of the Related Person's interest in the transaction, (iii) whether the Related Party Transaction was undertaken in the ordinary course of business of the Company, (iv) the availability of other sources of comparable products or services, (v) whether the Related Party Transaction was initiated by the Company or the Related Person, (vi) the purpose of, and the potential benefits to the Company of the Related Party Transaction, (vii) the approximate dollar value of the amount involved in the Related Party Transaction particularly as it related to the Related Person, and (viii) whether the Related Party Transaction is material to the Company. Further, the policy requires that all Related Party Transactions required to be disclosed in the Company's filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations.

All related persons transactions since January 1, 2024 which were required to be reported in "Transactions with Related Persons" were reviewed, approved or ratified in accordance with the procedures described above. In addition, since January 1, 2024, there has not been any transaction or series of similar transactions to which the Company was or is a party in which the amount involved exceeded or exceeds $120,000 and in which any of the Company's directors, executive officers, holders of more than 5% of any class of its voting securities, or any member of the immediate family of any of the foregoing persons, had or will have a direct or indirect material interest, other than compensation arrangements with directors and executive officers, which are described in "Item 11. Executive Compensation," and the transactions described or referred to below.

Transactions with Related Persons

Stockholders Agreement

In connection with the closing of the Company's proposed business combination transaction between certain of the Company's subsidiaries and North Peak Oil & Gas, LLC ("North Peak") and Century Oil and Gas Sub-Holdings, LLC ("Century Oil"), the Company will enter into a Stockholders Agreement (the "Stockholders Agreement") with North Peak and Century Oil (collectively, the "Stockholder").

The Stockholders Agreement will provide the Stockholder the right (but not obligation) to designate a number of nominees (each such person, and any other person designated for nomination by the Stockholder pursuant to the Stockholders Agreement, a "Stockholder Nominee") to the Board such that:

- From and after the date on which the closing of the mergers takes place (the "Closing Date"), until the first date on which the Stockholder has a Securities Ownership Percentage (as defined in the Stockholders Agreement) of less than 30.0%, the Stockholder may designate for nomination to the Board two Stockholder Nominees;

- If at any time the Stockholder has a Securities Ownership Percentage of less than 30.0% but greater than or equal to 15.0% (the "Stockholder Nomination Threshold"), the Stockholder may designate for nomination to the Board one Stockholder Nominee; and

- If at any time the Stockholder has a Securities Ownership Percentage equal to less than the Stockholder Nomination Threshold, (i) the Stockholder will no longer have the right to designate a Stockholder Nominee to the Board and (ii) the Company will no longer be obligated to nominate a Stockholder Nominee to the Board pursuant to the Stockholders Agreement.

The Stockholders Agreement will also provide that the Stockholder will be bound by certain "lock-up" provisions pursuant to the terms and conditions of the Stockholders Agreement, pursuant to which the Stockholder will be restricted from transferring any shares of Common Stock for a period of one year following the Closing Date, subject to customary exceptions. Further, the Stockholders Agreement will provide that, until the date that the Stockholder owns less than 10.0% of Amplify's issued and outstanding Common Stock (the "Trigger Date"), the Stockholder will be restricted from transferring any shares of Common Stock to (i) a Competitor (as defined in the Stockholders Agreement) or (ii) in a block trade that would result in a single person holding greater than 10.0% of Amplify's issued and outstanding Common Stock.

The Stockholders Agreement will contain certain standstill provisions which, among other things, will prohibit the Holder (as defined in the Stockholders Agreement) party thereto and certain of its affiliates (such affiliates, the "Restricted Parties") from (i) acquiring additional shares of Common Stock, subject to customary exceptions, (ii) soliciting proxies or influencing any voting of Common Stock or Amplify's other capital stock, (iii) directly or indirectly proposing transactions that would be reasonably likely to result in a change of control of Amplify, (iv) calling or seeking to call a meeting of stockholders of the Company or initiating a stockholder proposal or seeking additional representation on the Board, or otherwise seeking to control the management of Amplify and its controlled affiliates, including through the removal of directors, (v) forming, joining or knowingly encouraging or engaging in discussions regarding the formation of a "group" within the meaning of Section 13(d)(3) of the Exchange Act with non-affiliates with respect to the Amplify's securities, and (vi) publicly disclosing any intention, plan, or arrangement inconsistent with any of the foregoing. The standstill provisions will commence at the Closing Date and continue until the Trigger Date, unless an exemption or waiver is otherwise approved in advance in writing by Amplify.

The Stockholders Agreement will contain registration rights which, among other things and subject to certain restrictions, the Company will agree, on the terms set forth therein, to file with the SEC a registration statement registering for resale the Aggregate Merger Consideration (as defined in the Stockholders Agreement) and to conduct certain underwritten offerings upon the request of holders of Registrable Securities (as defined in the Stockholders Agreement). The Stockholders Agreement will also provide holders of Registrable Securities with certain customary piggyback registration rights.

Director Independence

The Company's standards for determining director independence require the assessment of directors' independence each year. A director cannot be considered independent unless the Board affirmatively determines that he or she does not have any relationship with management or the Company that may interfere with the exercise of his or her independent judgment, including any of the relationships that would disqualify the director from being independent under the rules of the NYSE.

The Board has assessed the independence of each non-employee director under the Company's guidelines and the independence standards of the NYSE. The Board affirmatively determined that Messrs. Craddock, Hamm, and Snyder and Mses. Adams, Douglas and Prasad are independent.

In connection with its assessment of the independence of each non-employee director, the Board also determined that (i) Mr. Snyder and Mses. Douglas and Prasad are independent, as defined in Section 10A of the Exchange Act, and under the standards set forth by the NYSE applicable to members of the Audit Committee and (ii) Messrs. Craddock and Snyder and Ms. Adams are independent under the standards set forth by the NYSE applicable to members of the Compensation Committee.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table summarizes the aggregate Deloitte fees for independent auditing, tax and related services for each of the years ended December 31, 2024 and 2023 (dollars in thousands), respectively:

	2024	2023
Audit fees(1)	$ 1,020,189	$ 1,255,000
Audit-related fees(2)	117,400	72,704
Tax fees(3)	107,000	240,210
All other fees(4)	—	—
Total	$ 1,244,589	$ 1,567,914

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. For each of the years ended December 31, 2024 and 2023, those fees primarily related to the (i) audit of our annual financial statements and internal controls over financial reporting included in our annual reports and (ii) the review of our quarterly financial statements filed on Form 10-Q.

(2) Audit-related fees represent amounts billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews.

(3) Tax fees represent amounts billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning.

(4) No such services were rendered by either Deloitte during the years ended December 31, 2024 and 2023.

Pre-Approval Policies and Procedures

The Audit Committee's charter requires the Audit Committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm.

The charter for the Audit Committee is available within the "Corporate Governance" section of our website at www.amplifyenergy.com.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

Our Consolidated Financial Statements are filed in Part II, “Item 8. Financial Statements and Supplementary Data” of our Original Form 10-K. For a listing of these statements and accompanying footnotes, see “Index to Financial Statements” on page F-1 of our Original Form 10-K.

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

The exhibits listed on the Exhibit Index below are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

Exhibit Index

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated May 5, 2019, by and among Amplify Energy Corp., Midstates Petroleum Company, Inc. and Midstates Holdings, Inc. (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-35364) filed on May 6, 2019).
3.1	Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
3.2	Certificate of Amendment to the Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc., dated August 6, 2019 (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
3.3	Third Amended and Restated Bylaws of Amplify Energy Corp. (incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 15, 2021).
4.1	Description of the Company's Capital Stock Registered Under Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.3 to Annual Report on Form 10-K (File No. 0001-35512) filed on March 5, 2020).
10.1	Amended and Restated Credit Agreement dated July 31, 2023, among Amplify Energy Operating LLC, as borrower, Amplify Acquisitionco LLC, as parent, the lenders party thereto and KeyBank National Association, as administrative agent and a letter of credit issuer (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 1, 2023).
10.2	Borrowing Base Redetermination, Commitment Increase and First Amendment to Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on October 25, 2024).
10.3#	Amplify Energy Corp. Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-8 (File No. 333-257071) filed on June 14, 2021).
10.4#	Amplify Energy Corp. 2024 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-8 (File No. 333-279868) filed on May 31, 2024).
10.5#	Form of 2024 TRSU Award Agreement (incorporated by reference to Exhibit 10.18 to the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 7, 2024).
10.6#	Form of 2024 PRSU Award Agreement (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 7, 2024).
10.7#	Form of 2024 TRSU Award Agreement (2024 EIP) (incorporated by reference to Exhibit 10.2 to the Company's Quarter Report on Form 10-Q (File No.001-35512) filed on August 7, 2024).
10.8#	Form of 2024 PRSU Award Agreement (2024 EIP) (incorporated by reference to Exhibit 10.3 to the Company's Quarter Report on Form 10-Q (File No.001-35512) filed on August 7, 2024).
10.9#	Form of 2025 TRSU Award Agreement (incorporated by reference to Exhibit 10.9 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
10.10#	Form of 2025 PRSU Award Agreement (incorporated by reference to Exhibit 10.10 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
10.11#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Eric Dulany (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.12#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and James Frew (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.13#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Daniel Furbee (incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.14#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Tony Lopez (incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.15#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Eric Willis (incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.

10.16#	Employment Agreement, dated November 1, 2023, by and between Amplify Energy Corp., Amplify Energy Services LLC and Martyn Willsher (incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 6, 2023.
10.17	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.16 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
19.1	Insider Trading Policy and Other Restrictions on Trading (incorporated by reference to Exhibit 19.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
21.1	List of Subsidiaries of Amplify Energy Corp (incorporated by reference to Exhibit 21.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
23.1	Consent of Cawley, Gillespie and Associates, Inc (incorporated by reference to Exhibit 23.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
23.2	Consent of Deloitte & Touche LLP (incorporated by reference to Exhibit 23.2 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 31.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 31.2 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
31.3*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.4*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (incorporated by reference to Exhibit 32.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
97.1	Amplify Energy Corp. Clawback Policy (incorporated by reference to Exhibit 97.1 of the Company's Annual Report on Form 10-K (File No. 001-35512) filed on March 7, 2024).
99.1	Report of Cawley, Gillespie and Associates, Inc. (incorporated by reference to Exhibit 99.1 of the Company's Annual Report on Form 10-K (File. No. 001-35512) filed on March 5, 2025).
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Schema Document
101.CAL*	Inline XBRL Calculation Linkbase Document
101.DEF*	Inline XBRL Definition Linkbase Document
101.LAB*	Inline XBRL Labels Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document)
*	Filed or furnished as an exhibit to this Amendment No. 1 to Annual Report on Form 10-K.
#	Management contract or compensatory plan or arrangement.

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.

Amplify Energy Corp.
(Registrant)

Date: April 17, 2025

By: /s/ James Frew
Name: James Frew
Title: Senior Vice President and Chief Financial 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 their capacities and on the dates indicated.

Name	Title (Position and Amplify Energy Corp.)	Date
/s/ Martyn Willsher Martyn Willsher	President and Chief Executive Officer (Principal Executive Officer)	April 17, 2025
/s/ James Frew James Frew	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	April 17, 2025
/s/ Eric Dulany Eric Dulany	Vice President and Chief Accounting Officer (Principal Accounting Officer)	April 17, 2025
/s/ Christopher W. Hamm Christopher W. Hamm	Chairman and Director	April 17, 2025
/s/ Deborah Adams Deborah Adams	Director	April 17, 2025
/s/ James E. Craddock James E. Craddock	Director	April 17, 2025
/s/ Patrice Douglas Patrice Douglas	Director	April 17, 2025
/s/ Vidisha Prasad Vidisha Prasad	Director	April 17, 2025
/s/ Todd R. Snyder Todd R. Snyder	Director	April 17, 2025