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 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas	**72-1121985**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
5718 Westheimer Road, Suite 700 Houston, Texas	**77057-5745**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(713) 626-8525**

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, par value $0.00001	WTI	New York Stock Exchange

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 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 the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

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

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

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

The aggregate market value of the registrant's common stock held by non-affiliates was approximately $209,332,671 based on the closing sale price of $2.14 per share as reported by the New York Stock Exchange on June 30, 2024.

The number of shares of the registrant's common stock outstanding on February 28, 2025 was 147,635,709.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Form 10-K.

W&T OFFSHORE, INC.
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (“Form 10-K”) 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”). All statements, other than statements of historical fact included in this Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. These forward-looking statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. Although we believe that these forward-looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions.

Known material risks that may affect our financial condition and results of operations are discussed in Item 1A. *Risk Factors*, and market risks are discussed in Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*, of this Form 10-K and may be discussed or updated from time to time in subsequent reports filed with the SEC.

When used in this Form 10-K, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “forecast,” “may,” “objective,” “plan,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We assume no obligation, nor do we intend, to update these forward-looking statements, unless required by law. Unless the context requires otherwise, references in this Form 10-K to “W&T”, “we,” “us,” “our” and the “Company” refer to W&T Offshore, Inc. and its consolidated subsidiaries.

The information included in this Form 10-K includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, capital for sustained production levels, expected production and operating costs, reserves, hedging activities, capital expenditures, return of capital, improvement of recovery factors and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially.

Factors (but not necessarily all the factors) that could cause results to differ include, among others:

- the regulatory environment, including availability or timing of, and conditions imposed on, obtaining and/or maintaining permits and approvals, including those necessary for drilling and/or development projects;
- the impact of current, pending and/or future laws and regulations, and of legislative and regulatory changes and other government activities, including those related to permitting, drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- inflation levels;
- global economic trends, geopolitical risks and general economic and industry conditions, such as the global supply chain disruptions and the government interventions into the financial markets and economy in response to inflation levels and world health events;
- volatility of oil, NGL and natural gas prices;
- the global energy future, including the factors and trends that are expected to shape it, such as concerns about climate change and other air quality issues, the transition to a low-emission economy and the expected role of different energy sources;

- supply of and demand for oil, NGLs and natural gas, including due to the actions of foreign producers, importantly including OPEC and other major oil producing companies ("OPEC+") and change in OPEC+'s production levels;
- disruptions to, capacity constraints in, or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures, meet our working capital requirements or fund planned investments;
- price fluctuations and availability of natural gas and electricity;
- our ability to use derivative instruments to manage commodity price risk;
- our ability to meet our planned drilling schedule, including due to our ability to obtain permits on a timely basis or at all, and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- drilling and production results, lower–than–expected production, reserves or resources from development projects or higher–than–expected decline rates;
- our ability to obtain timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells;
- changes in tax laws;
- effects of competition;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- asset impairments from commodity price declines;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- the creditworthiness and performance of our counterparties with respect to our hedges;
- impact of derivatives legislation affecting our ability to hedge;
- failure of risk management and ineffectiveness of internal controls;
- catastrophic events, including tropical storms, hurricanes, earthquakes, pandemics or other world health events;
- environmental risks and liabilities under U.S. federal, state, tribal and local laws and regulations (including remedial actions);
- potential liability resulting from pending or future litigation;
- our ability to recruit and/or retain key members of our senior management and key technical employees;
- information technology failures or cyberattacks; and
- governmental actions and political conditions, as well as the actions by other third parties that are beyond our control.

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

All forward-looking statements, expressed or implied, included in this Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

SUMMARY RISK FACTORS

The following is a summary of the principal risks described in more detail under Part I, Item 1A. *Risk Factors*, in this Form 10-K.

Market and Competitive Risks

- Oil, NGL and natural gas prices can fluctuate widely due to a number of factors that are beyond our control.
- If oil, NGL and natural gas prices decrease from their current levels, we may be required to further reduce the estimated volumes and future value associated with our total proved reserves or record impairments to the carrying values of our oil and natural gas properties.
- Commodity derivative positions may limit our potential gains.
- Competition for oil and natural gas properties and prospects is intense; some of our competitors have larger financial, technical and personnel resources that may give them an advantage in evaluating and obtaining properties and prospects.
- Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.
- If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.

Operating Risks

- Production periods and relatively short reserve lives for our Gulf of America properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil, NGL and natural gas prices.
- We are not insured against all of the operating risks to which our business is exposed.
- We conduct exploration, development and production operations on the deep shelf and in the deepwater of the Gulf of America, which presents unique operating risks.
- We may not be in a position to control the timing of development efforts, associated costs or the rate of production of the reserves from our non-operated properties.
- We are subject to numerous risks inherent to the exploration and production of oil and natural gas.
- We are subject to drilling and other operational hazards.
- The geographic concentration of our properties in the Gulf of America subjects us to an increased risk of loss of revenues or curtailment of production from factors specifically affecting the Gulf of America, including hurricanes.
- A significant portion of our production, revenue and cash flow is concentrated in our Mobile Bay Properties.
- New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.
- Estimates of our proved reserves depend on many assumptions that may turn out to be inaccurate.
- Prospects that we decide to drill may not yield oil or natural gas in commercial quantities or quantities sufficient to meet our targeted rates of return.
- We may not realize all of the anticipated benefits from our future acquisitions.
- Our future acquisitions and divestitures could expose us to potentially significant liabilities, including plugging and abandonment and decommissioning liabilities.
- Our operations could be adversely impacted by security breaches, including cybersecurity breaches, which could affect the systems, processes and data needed to run our business.
- The loss of members of our senior management could adversely affect us.
- There may be circumstances in which the interests of significant stockholders could conflict with the interests of our other stockholders.

Capital Risks

- Our debt level could negatively affect our financial condition, results of operations and business prospects.
- Our debt agreements contain restrictions that limit our abilities to incur certain additional debt or liens or engage in other transactions, which could limit growth and our ability to respond to changing conditions.

- We have significant capital needs to conduct our operations and replace our production, and our ability to access the capital and credit markets to raise capital or refinance our existing indebtedness on favorable terms may be limited by industry conditions and financial markets.
- If we default on our secured debt, the value of the collateral securing our secured debt may not be sufficient to ensure repayment of all such debt.
- We may not be able to repurchase the 10.75% Senior Second Lien Notes upon a change of control.
- We may be required to post cash collateral pursuant to our agreements with sureties under our existing or future bonding arrangements, which could 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.

Legal, Government and Regulatory Risks

- We are subject to numerous environmental, health and safety regulations which are subject to change and may also result in material liabilities and costs.
- We may be unable to provide financial assurances in the amounts and under the time periods required by the BOEM if the BOEM submits future demands to cover our decommissioning obligations.
- Additional deepwater drilling laws, regulations and other restrictions, delays and other offshore-related developments in the Gulf of America may have a material adverse effect on our business, financial condition, or results of operations.
- Our estimates of future ARO may vary significantly from period to period, and unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.
- We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business.
- We are subject to laws, rules, regulations and policies regarding data privacy and security.
- The Inflation Reduction Act of 2022 could accelerate the transition to a low-carbon economy and could impose new costs on our operations.
- We are subject to risks arising from climate change, including risks related to energy transition, which could result in increased costs and reduced demand for the oil and natural gas we produce and physical risks which could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.
- Increasing attention to ESG matters may impact our business.
- Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.
- Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.
- Our articles of incorporation and bylaws, as well as Texas law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.
- While we paid quarterly dividends during 2024, there can be no assurance that we will pay dividends in the future.

GLOSSARY

The following are abbreviations and definitions of certain terms used in this Annual Report on Form 10-K.

Bbl. One stock tank barrel or 42 United States gallons liquid volume.

Bcf. Billion cubic feet, typically used to describe the volume of natural gas.

Boe. Barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of oil or condensate.

Boe/d. Barrel of oil equivalent per day.

BOEM. Bureau of Ocean Energy Management.

BSEE. Bureau of Safety and Environmental Enforcement.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Conventional shelf. Water depths less than 500 feet.

Deep shelf. Water depths greater than 500 feet and less than 15,000 feet.

Deepwater. Water depths greater than 500 feet.

Development. The phase in which petroleum resources are brought to the status of economically producible by drilling developmental wells and installing appropriate production systems.

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

Dry hole. A well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. Refers to a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

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

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

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

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet, typically used to describe the volume of a gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet, typically used to describe the volume of a gas.

Natural gas. A combination of light hydrocarbons that, in average pressure and temperature conditions, are found in a gaseous state. In nature, it is found in underground accumulations and may potentially be dissolved in oil or may also be found in a gaseous state.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of pressure and temperature. NGLs consist primarily of ethane, propane, butane and natural gasoline.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange.

Oil. Crude oil and condensate.

OCS. Outer continental shelf.

ONRR. Office of Natural Resources Revenue. The agency performs the offshore royalty and revenue management functions of the former Minerals Management Service.

OPEC+. Organization of Petroleum Exporting Countries and other state controlled companies.

Productive well. A well that is found to have economically producible hydrocarbons.

Proved developed reserves. Proved 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. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves. Those quantities of oil, NGLs 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 SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

Proved undeveloped reserves (“PUDs”). Proved reserves of any category that are expected to be recovered from future wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped reserves in Rule 4-10(a)(31) of Regulation S-X.

PV-10. The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of the estimation without future escalation. PV-10 excludes cash flows for asset retirement obligations, general and administrative expenses, derivatives, debt service and income taxes.

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

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.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil and natural gas for each month within the twelve-month period preceding the reported period, adjusted by lease for market differentials (quality, transportation fees, energy content and regional price differentials). The SEC provides a complete definition of pricing in “Modernization of Oil and Gas Reporting” (Final Rule, Release Nos. 33-8995; 34-59192).

Unproved properties. Properties with no proved reserves.

WTI. West Texas Intermediate grade crude oil. A light crude oil produced in the United States with an American Petroleum Institute gravity of approximately 38-40 and the sulfur content is approximately 0.3%.

PART I

ITEM 1. BUSINESS

W&T Offshore, Inc. ("we," "our" or "us") is a publicly held Texas corporation. We are an independent oil and natural gas producer with substantially all our operations offshore in the Gulf of America. We are active in the acquisition, exploration and development of oil and natural gas properties. We operate in one reportable segment.

Since our founding in 1983 by our Chairman and Chief Executive Officer, Tracy Krohn, we have developed significant technical expertise in finding and developing properties in the Gulf of America with existing production which provide the best opportunity to achieve a return on our invested capital. We have successfully discovered and produced properties on the conventional shelf and in the deepwater across the Gulf of America.

We have continually grown our footprint in the Gulf of America through acquisitions, exploration and development. As of December 31, 2024, we held working interests in 52 offshore producing fields in federal and state waters. Our producing fields are located in federal and state waters in the Gulf of America in water depths ranging from less than 10 feet up to 7,300 feet. The reservoirs in our offshore fields are generally characterized as having high porosity and permeability, with higher initial production rates relative to other domestic reservoirs.

Our acreage, well, production and reserves information are described in more detail under Part I, Item 2. *Properties,* in this Form 10-K.

Business Strategy

The Gulf of America offers unique advantages, and we are uniquely positioned to create value with a diverse portfolio in valuable shelf, deep shelf and deepwater projects. Our diverse portfolio of operations in the Gulf of America enables stacked pay development, attractive primary production, and recompletion opportunities. We use advanced seismic and geoscience tools to execute successful drilling projects.

In managing our business, we are focused on optimizing production and increasing reserves in a profitable and prudent manner, while managing cash flows to meet our obligations and investment needs. Our goal is to pursue lower risk, high rate of return projects and develop oil and natural gas resources that allow us to grow our production, reserves and cash flow in a capital efficient manner, and organically enhance the value of our assets helping to ensure the long-term sustainability of our business.

We follow a proven and consistent business strategy:

- *Focus on free cash flow generation*. Our strong production base and cost optimization has generated steady free cash flows. The Gulf of America is an area where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve high rates of return on our invested capital.
- *Maintain high-quality conventional asset base with low decline.* We generate incremental production from probable reserves and possible reserves due to natural drive mechanisms. Typical fields with high-quality sands offer mechanisms superior to primary depletion and they often enjoy incremental reserve adds annually. Fewer conventional wells are required to develop these fields. While we continue to utilize proven techniques and technologies, we will also continuously seek efficiencies in our drilling, completion and production techniques in order to optimize ultimate resource recoveries, rates of return and cash flows.
- *Capitalize on unique and accretive acquisition opportunities.* We strategically pursue the acquisition of compelling producing assets that generate cash flows at attractive valuations with upside potential and optimization opportunities. We may also use our capital flexibility to pursue value-enhancing, bolt-on acquisitions to opportunistically improve our positions in existing assets.

- *Reduce costs to improve margins.* We grow in opportunistic ways as we manage our balance sheet prudently and reinvest free cash flow. Our existing portfolio of 204 structures (150 of which we operate) provides a key advantage when evaluating and developing prospect opportunities and serves to reduce capital expenditures and maximize our returns on capital expenditures.

- *Preserve ample liquidity and maintain financial flexibility.* By operating within our free cash flow, we are able to improve liquidity and optimize our balance sheet.

- *Maintain safety, sustainability and corporate responsibility as key principles for operations across all areas of our business.* We are focused on maintaining high standards of safety, environmental responsibility and corporate citizenship across all elements of our business. We closely monitor safety performance and consistently take steps to improve our performance. We strive to execute our business plan while simultaneously minimizing our environmental footprint, including emissions, potential spills and other impacts. Production from the Gulf of America continues to provide some of the lowest greenhouse gas ("GHG") emissions intensity due to the nature of subsea wells and established offshore pipelines and we continue to strive to lower our GHG emissions. Finally, we aim to be a good corporate citizen in the regions and communities where we operate.

We intend to execute the following elements of our business strategy in order to achieve our strategic goals:

- Exploit existing and acquired properties to add additional reserves and production;

- Explore for reserves on our extensive acreage holdings and in other areas of the Gulf of America;

- Acquire reserves with substantial upside potential and additional leasehold acreage complementary to our existing acreage position at attractive prices;

- Continue to manage our balance sheet in a prudent manner and continuing our track record of financial flexibility in any commodity price environment; and

- Carry out our business strategy in a safe and socially responsible manner.

We continually monitor current and forecasted commodity prices to assess if changes to our plans are needed. Our significant inside ownership ensures that executive management's interests are highly aligned with those of our shareholders, thus incentivizing executive management to maximize value and mitigate risk in executing our business strategy, generating shareholder value.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas companies and individual producers and operators, in acquiring oil and natural gas properties, contracting for drilling equipment and securing trained personnel. Many of these competitors are large, well-established companies that have financial and other resources substantially greater than ours. As a result, our competitors may be better able to withstand the financial pressures of significant declines in oil and natural gas prices, unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may have a greater ability to provide the extensive regulatory financial assurances required for offshore properties and to absorb the burdens from changes in applicable laws and regulations. As a smaller oil and natural gas company, however, we have greater flexibility in decision making, can adapt quicker to market changes, have the potential for higher profit margins on smaller projects and have the opportunity to develop innovative strategies without the constraints of large-scale operations.

Oil and Natural Gas Marketing and Delivery Commitments

The market for our oil, NGL and natural gas production depends on factors beyond our control, including the extent of domestic production and imports of oil, NGLs and natural gas; the proximity and capacity of natural gas pipelines and other transportation facilities; the demand for oil, NGLs and natural gas; the marketing of competitive fuels; and the effect of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

We sell our oil, NGLs and natural gas to third-party customers. The terms of sale under the majority of existing contracts are short-term, usually one year or less in duration. The prices received for oil, NGL and natural gas sales are generally tied to monthly or daily indices as quoted in industry publications.

We are not dependent upon, or contractually limited to, any one customer or small group of customers. In 2024, approximately 44% and 12% of our receipts from sales of oil, NGLs and natural gas were received from BP Products North America and Chevron-Texaco, respectively, with no other customer comprising greater than 10% of our 2024 receipts from sales of oil, NGLs and natural gas. Given the commoditized nature of the products we produce and market and the location of our production in the Gulf of America, we believe the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and natural gas production, as we believe that replacement customers could be obtained in a relatively short period of time on terms, conditions, and pricing substantially similar to those currently existing.

Seasonal Nature of Our Business

Generally, the demand for and price of natural gas increases during the winter months and decreases during the summer months. However, these seasonal fluctuations are somewhat reduced because during the summer, pipeline companies, utilities, local distribution companies and industrial users purchase and place a portion of their anticipated winter requirements of natural gas into storage facilities. As utilities continue to switch from coal to natural gas, some of this seasonality has been reduced as natural gas is used for both heating and cooling. In addition, the demand for oil is higher in the winter months but does not fluctuate seasonally as much as natural gas.

Seasonal weather changes affect our operations. Tropical storms and hurricanes occur in the Gulf of America during the summer and fall, which can require us to evacuate personnel and shut in production until a storm subsides. Also, periodic storms during the winter often impede our ability to safely load, unload and transport personnel and equipment, which can delay production and sales of our oil and natural gas.

Impact of Inflation

The United States has experienced a rise in inflation since October 2021. Inflation peaked during mid-2022 at 9.1% but the rate of inflation has been gradually declining since the second half of 2022 according to the Consumer Price Index (the “CPI”). The annual inflation rate for December 2024 was 2.9%, a decrease from the 3.4% rate for December 2023. However, the annual inflation rate for January 2025 was 3.0%, an increase from the 2.9% in December 2024. Beginning in September 2024, the Federal Reserve made three cuts to the target federal funds rate, bringing the target federal funds range down to 4.25% to 4.50%, easing monetary policy for the first time in four years due to progress in inflation moving sustainably toward 2.0%. The Summary of Economic Projections published by the Federal Reserve in December 2024 points to another 50 basis points of cuts in 2025. However, if inflation continues to increase, it is possible the Federal Reserve would take whatever action they deem necessary to bring inflation down and to ensure price stability, including target federal funds rate increases, which could have the effects of raising the cost of capital and depressing economic growth, either or both of which could negatively impact our business.

Due to the cyclical nature of the oil and gas industry, fluctuating demand for oilfield goods and services can put pressure on the pricing structure within our industry. As commodity prices rise, the cost of oilfield goods and services generally also increases, while during periods of commodity price declines, decreases in oilfield costs typically lag behind commodity price decreases. Continued inflationary pressures and increased commodity prices may also result in increases to the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise. While we are experiencing some inflationary pressure for certain costs, including employees and vendors, such cost increases did not materially impact our 2024 financial condition or results of operations, and we currently do not expect them to materially impact our 2025 financial results or operations.

Insurance Coverage

In accordance with industry practice, we maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed. In general, our current insurance policies cover risks incident to the operation of oil and natural gas wells, including, but not limited to, personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or other environmental damage and the suspension of operations. We do not carry business interruption insurance.

Our general and excess liability policies provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. Our Energy Package (defined as certain insurance policies relating to our oil and natural gas properties, which include named windstorm coverage) contains multiple layers of insurance coverage for our operating activities, with higher limits of coverage for higher valued properties and wells. Under the Energy Package, the limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. With respect to coverage for named windstorms, we have a $162.5 million aggregate limit covering one of our higher valued properties, and $150.0 million for all other properties subject to four region retentions ranging from $2.5 million to $15.0 million on the conventional shelf properties and $10.0 million on the deepwater properties.

We believe that our coverage limits are sufficient and are consistent with our exposure; however, we cannot insure against all possible losses. As a result, any damage or loss not covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

We re-evaluate the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that we will be able to insure our business activities at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Environmental, Health and Safety Matters and Government Regulations

Our operations are subject to complex and stringent federal, state and local laws and regulations that, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment and the discharge and disposal of waste materials and, to the extent waste materials are transported and disposed of in onshore facilities, remediation of any releases of those waste materials from such facilities. The federal environmental laws and regulations applicable to us and our operations include, among others, the following:

- The Resource Conservation and Recovery Act, as amended, regulates the generation, transportation, storage, treatment and disposal of non-hazardous and hazardous wastes and can require cleanup of hazardous waste disposal sites;
- The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, ("CERCLA") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment;
- The Clean Air Act, as amended (the "CAA"), and comparable state and local requirements restrict the emission of air pollutants from many sources through the imposition of air emission standards, construction and operating permitting programs and other compliance requirements;
- The Clean Water Act, as amended, and analogous state laws, prohibit any discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, except in compliance with permits issued by federal and state governmental agencies;

- The Oil Pollution Act of 1990, as amended (the "OPA"), holds owners and operators of offshore oil production or handling facilities, including the lessee or permittee of the area where an offshore facility is located, strictly liable for the costs of removing oil discharged into waters of the United States, including the OCS or adjoining shorelines, and for certain damages from such spills;
- The Endangered Species Act, as amended, restricts activities that may affect federally identified endangered and threatened species or their habitats;
- The Migratory Bird Treaty Act, as amended, implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds; and
- The National Environmental Policy Act, as amended, requires careful evaluation of the environmental impacts of oil and natural gas production activities on federal lands.

In addition to the federal laws and regulations above, we are also subject to the requirements of the Occupational Safety and Health Administration ("OSHA") and comparable state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes, where applicable, require that we organize and/or disclose information about hazardous materials used or produced in our operations. Such laws and regulations also require us to ensure our workplaces meet minimum safety standards and provide for compensation to employees injured as a result of our failure to meet these standards as well as civil and/or criminal penalties in certain circumstances. We believe that we are in substantial compliance with all such existing laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations.

Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often costly to comply with, and a failure to comply may result in substantial administrative, civil and criminal penalties; the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures; the occurrence of restrictions, delays or cancellations in the permitting, or development or expansion of projects; and the issuance of orders enjoining some or all of our operations in affected areas. We consider the costs of environmental compliance to be a necessary and manageable part of our business. However, based on policy and regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to compliance with the protection of the environment have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters. See Item 1A. *Risk Factors* contained herein for further discussion of governmental regulation and ongoing regulatory changes, including with respect to environmental matters.

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. Rules and regulations affecting the oil and natural gas industry are under consistent review for amendment or expansion, which could increase the regulatory burden and the potential sanctions for noncompliance. Relatedly, numerous federal and state departments and agencies are authorized to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Historically, our compliance with existing requirements has not had a material adverse effect on our financial position, results of operations or cash flows. Because such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Although the regulatory burden on the oil and natural gas industry may increase our cost of doing business, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Exploration and Production

Statutes, rules and regulations affecting exploration and production are subject to extensive and continually changing regulations as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability. Our exploration and production are subject to various types of regulation at the federal, state and local levels. These types of regulation include, but are not limited to, requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most jurisdictions in which we operate also regulate one of more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the plugging and abandonment of wells and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines; and
- the produced water and disposal of wastewater, drilling fluids and other liquids and solids utilized or produced in the drilling and extraction process.

Our operations on federal oil and natural gas leases in the OCS waters of the Gulf of America are subject to regulation by the BSEE, the BOEM and the ONRR, all of which are agencies of the U.S. Department of the Interior (the "DOI"). The BSEE and the BOEM work to ensure the development of energy and mineral resources on the OCS is done in a safe and environmentally and economically responsible way. The ONRR performs the offshore royalty and revenue management functions of the former Minerals Management Service.

The federal government cannot conduct offshore lease sales without the development and approval of a National Outer Continental Shelf Oil and Gas Leasing Program (the "OCS Program"). The Outer Continental Shelf Lands Act (the "OCSLA") authorizes the Secretary of the Interior to establish a schedule of lease sales for a five-year period. There is no requirement under the OCSLA that mandates any sales in any locations, nor does the law prescribe any specific timing for the development of the OCS Program. These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms. Prior to commencement of offshore operations, lessees must obtain the BOEM's approval for exploration, development and production plans. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency (the "EPA"), lessees must obtain a permit from the BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and decommissioning of facilities, structures and pipelines.

In August 2022, Congress passed the Inflation Reduction Act (the "IRA") which requires that the BOEM must offer at least two million acres for oil and natural gas leasing on the OCS before the BOEM can issue a lease for offshore wind development. The IRA also raised the royalty rate for certain offshore leases from the current 12.5% to 16.67% and capped the rate at 18.75% for ten years.

In September 2023, consistent with the requirements of the IRA concerning offshore conventional and renewable energy leasing, the DOI announced its proposed 2024 – 2029 OCS Program. The proposed OCS Program includes a maximum of three potential oil and natural gas lease sales in the Gulf of America scheduled in 2025, 2027 and 2029. In December 2024, BOEM released a draft environmental review around Lot Sale 262 which was to occur in 2025. The review studied the effects of four leasing options on marine, coastal and human environments and found that the impact on resources such as air quality, birds and recreational fishing was often described as "negligible." BOEM estimates that a final environmental impact statement will not be released until September 2025, with a final decision to be made in January 2026. As a result, Lot Sale 262 is expected to be delayed until sometime in 2026.

Decommissioning and Financial Assurance Requirements

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities in the OCS. In April 2024, BOEM released a final rule that changes the way BOEM evaluates the financial health of companies and offshore assets in setting financial assurance requirements. Under the new rule, BOEM streamlined the criteria used to evaluate the financial health of an energy company down to two factors: (i) the company's credit rating, and (ii) the ratio of the value of the company's proved reserves to decommissioning liability associated with those reserves. The new rule also codifies the usage of BSEE decommissioning estimates to evaluate supplemental financial assurance requirements and allows third party guarantors (upon agreement with BOEM) to provide limited guarantees to specific amounts or specific leases instead of the blanket guarantees that have been used in the past. Finally, the new rule also requires a base financial assurance requirement of $500,000 for federal rights-of-use and easements ("RUEs") to match the requirement for state RUEs. To provide the industry with flexibility to meet the new financial assurance requirements, BOEM will allow current lessees and grant holders to request phased-in payments over a three-year period. BOEM estimates that the industry will be required to provide $6.9 billion in new financial assurances under the new rule, which took effect on June 29, 2024. Following the announcement of the new rule, a series of lawsuits from both states and industry groups have been filed against BOEM to block the implementation of the new rule. We are actively monitoring ongoing litigation with respect to the new rule.

Regulation of Sales and Transportation of Oil, NGLs and Natural Gas

Our sales of oil, NGLs and natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. The interstate transportation and sale for resale of oil, NGLs and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters.

The OCSLA, which is administered by the BOEM and the Federal Energy Regulatory Commission (the "FERC"), requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out the OCSLA's mandate is to increase transparency in the OCS market, to provide producers and shippers assurance of open access service on pipelines located on the OCS, and to provide non-discriminatory rates and conditions of service on such pipelines. Interstate transportation rates for oil, NGLs and natural gas are regulated by the FERC. In general, interstate oil, condensate, NGL and natural gas pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. The FERC has established an indexing system for such transportation, which generally allows such pipelines to take an annual inflation-based rate increase. In certain limited circumstances, intrastate transmission of natural gas may also be affected directly or indirectly by the FERC's regulations.

The price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. We do not believe that the regulatory decisions or activities relating to interstate or intrastate oil or NGL pipelines will affect us in a way that materially differs from the way they affect other oil and NGL producers or marketers. Other than as described above, our sales of liquids, which include oil, condensate and NGLs, are not currently regulated and are transacted at market prices.

Although natural gas prices are currently unregulated, Congress has historically been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas may be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

Climate Change

The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States. President Biden made addressing climate change, including the restriction or elimination of GHG emissions, a priority in his administration's agenda, and laws such as the IRA advance numerous climate-related objectives. Additionally, numerous proposals have been made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHG as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the EPA has adopted regulations under the existing CAA that, among other things, impose pre-construction and operating permit requirements on certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources and implement New Source Performance Standards directing the reduction of methane from certain new, modified or reconstructed facilities in the oil and natural gas sector. Compliance with these rules or others could result in increased compliance costs on our operations.

In March 2024, the EPA published its final rule establishing more stringent methane rules for new, modified, and reconstructed facilities, known as Quad Ob, as well as standards for existing sources for the first time ever, known as Quad Qc. Under the final rules, states have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a “super emitter” response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and its requirements will be subject to legal challenges and regulatory revision, so we are unable to predict at this time the scope of any final regulatory requirements and the expected cost to comply with such requirements. Any increase in regulatory scope and oversight may increase compliance costs or mitigation costs for our operations.

At the international level, there exists the United Nations-sponsored “Paris Agreement,” which is a non-binding agreement among participating nations to limit their GHG emissions through individually-determined emissions reduction goals every five years after 2020. Most recently, at the 29th Conference of the Parties (“COP29”), developed nations signed onto an agreement to help channel “at least” $300.0 billion annually into developing countries by 2035 to support climate change efforts. In addition, participants finalized the remaining sections of the Paris Agreement, meaning all elements of the Paris Agreement have been finalized nearly 10 years after it was signed. On January 20, 2025, President Trump signed an executive order requiring the U.S. Ambassador to the United Nations to submit formal written notification of the United States’ withdrawal from the Paris Agreement. Under the terms of the Paris Agreement, withdrawal of a party will take effect one year after receipt of written notice of withdrawal. According to the executive order, however, the United States will consider its withdrawal from the Paris Agreement and any attendant obligations to be effective immediately upon this provision of notification. The impacts of these orders, pledges and agreements, and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement and subsequent climate conferences or other international conventions cannot be predicted at this time and it is unclear what additional initiatives may be adopted or implemented that may have a negative impact on our financial condition.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risk regarding climate change. In the United States, President Biden issued several executive orders calling for more expansive action to address climate change and limit new oil and gas operations on federal lands and waters. In addition, on January 26, 2024, President Biden announced a temporary pause on pending decisions on new exports of liquefied natural gas (“LNG”) to countries that the United States does not have free trade agreements with pending U.S. Department of Energy (“DOE”) review of the underlying analyses for authorizations. The pause was intended to provide time to integrate certain considerations, including potential energy cost increases for consumers and manufacturers and the latest assessment of the impact of GHG emissions, to ensure adequate safeguards against health risks are in place. On January 20, 2025, the DOE announced that it would resume processing export permit applications for new LNG projects following direction provided in an executive order signed on January 20, 2025. On February 14, 2025, the DOE announced a new export authorization for the Commonwealth LNG program proposed for Cameron Parish, Louisiana.

Additionally, the IRA contains hundreds of billions of dollars in incentives for the development of renewable energy, clean fuels, electric vehicles and supporting infrastructure, and carbon capture and sequestration, among other provisions. These incentives could further accelerate the transition of the United States’ economy away from the use of fossil fuels toward lower-or zero-carbon emissions alternatives. The IRA also imposes the first ever federal fee on the GHG emissions through a methane emissions charge. Under this rule, finalized in November 2024, the methane emissions charge for 2024 was established at $900 per ton emitted over annual methane emissions thresholds, and would increase to $1,200 in 2025, and $1,500 in 2026. The implementation of revised air emission standards could result in stricter permitting requirements, which could delay, limit or prohibit our ability to obtain such permits and result in increased compliance costs on our operations, including expenditures for pollution control equipment, the costs of which could be significant. In February 2025, Congress filed a resolution under the Congressional Review Act to repeal the methane emissions charge.

Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. We are not currently a defendant in any of these lawsuits but could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Additionally, our access to capital may be impacted by climate change policies. Stockholders and bondholders currently invested in fossil fuel energy companies such as ours, but concerned about the potential effects of climate change, may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices that favor "clean" power sources, such as wind and solar, making those sources more attractive, and these lenders may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made "net zero" carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, there is the possibility that financial institutions will be required to adopt additional policies that limit funding to fossil fuel energy companies.

In October 2023, the Federal Reserve, Office of the Comptroller of the Currency and the Federal Deposit Insurance Corporation (the "FDIC") released a finalized set of principles guiding financial institutions with $100 billion or more in assets on the management of physical and transition risks associated with climate change. While we cannot predict what additional developments may arise from these various activities, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and operations.

Separately, the U. S. Securities and Exchange Commission ("SEC") issued a final rule in March 2024 that established a framework for the reporting of climate risks, targets and metrics. In April 2024, less than a month after the issuance of the final rule, the SEC issued an order staying the rules in April 2024. The stay followed a number of petitions for review filed against the SEC that were consolidated before the US Court of Appeals for the Eighth Circuit. The SEC has also announced that it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege that an issuer's existing climate disclosures are misleading, deceptive or deficient. Such agency action could also increase the potential for private litigation. Non-compliance with these new laws may result in the imposition of substantial fines or penalties. Any new laws or regulations imposing more stringent requirements on our business related to the disclosure of climate related risks may result in reputation harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, increased compliance costs resulting from the development of any disclosures, and increased costs of and restrictions on access to capital to the extent we do not meet any climate-related expectations or requirements of financial institutions.

Finally, some scientists have concluded that increasing concentrations of GHG emissions in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other extreme climatic events, as well as chronic shifts in temperature and precipitation patterns. Our offshore operations are particularly at risk from severe climatic events, which have the potential to cause physical damage to our assets and thus could have an adverse effect on our exploration and production operations. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we produce. While our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

As discussed above, in January 2025, President Trump announced that the United States was withdrawing from the Paris Agreement. He also issued additional executive orders aimed at boosting fossil fuels and undoing Biden-era initiatives to limit GHG emissions. He declared a national energy emergency and revoked many of President Biden's executive orders on climate change. New orders instruct agencies to roll back restrictions on offshore drilling and reconsider protections for Alaska's Arctic National Wildlife Refuge. President Trump also issued a moratorium on new wind power projects on federal lands, pausing new leases and permits for both onshore and offshore wind farms. He revoked an executive order that compelled government regulators to assess the risks of climate change to the financial system and he instructed agencies to review any regulations that might “burden the development of domestic energy resources.” While no definitive actions have been taken, it is anticipated that such agency review could result in changes to major Biden administration climate policies, including EPA rules limiting emissions from coal- and natural gas-fired power plants and the methane emissions charge discussed above.

Financial Information

We operate our business as a single segment. See *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K for our financial information.

Human Capital Resources

As of December 31, 2024, we had approximately 400 employees who conduct our business in Texas, Alabama, Louisiana and the Gulf of America. Our workforce in Texas is primarily composed of our corporate employees, including our executive officers, drilling and production managers, technical engineers and administrative and support staff. Our employees in Alabama, Louisiana and the Gulf of America are primarily composed of skilled labor who conduct our field operations and manage third-party personnel used in support of our field operations.

We consider our employees to be our most valuable asset and believe that our success depends on our ability to attract, develop and retain our employees. We strive to provide a work environment that attracts and retains the top talent in the industry, reflects our core values and demonstrates these values to the communities in which we operate.

Diversity and Inclusion

We recognize that a diverse workforce provides the best opportunity to obtain unique perspectives, experiences and ideas to help our business succeed, and we are committed to providing a diverse and inclusive workplace to attract and retain talented employees. From recent graduates to experienced hires, we seek to attract and develop top talent to continue building a unique blend of cultures, backgrounds, skills and beliefs that mirror the world we live in.

The key to our past and future successes is promoting a workforce culture that embraces integrity, honesty and transparency to those with whom we interact, and fosters a trusting and respectful work environment that embraces changes and moves us forward in an innovative and positive way. Our Code of Business Conduct and Ethics prohibits illegal discrimination or harassment of any kind.

Safety, Health and Wellness

The success of our business is fundamentally connected to the well-being of our people. We are committed to the safety, health and wellness of our employees.

Our highest priorities are the safety of all personnel and protection of the environment. We actively promote the highest standards of safety behavior and environmental awareness and strive to meet or exceed all applicable local and natural regulations. To drive a culture of personnel safety in our operations, we operate under a comprehensive Safety and Environmental Management System (“SEMS”). Our 2024 total recordable incident rate for employees was 0.00, which is far below the industry average for the Gulf of America from 2023 of 0.51. Although incident reporting practices are subject to some subjectivity and vary by operator, we have historically had below average incident rates compared to the industry average for the Gulf of America, and we strive to continue to excel at protecting our personnel. Our HSE&R group is comprised of a Vice President, Environmental, Safety and Regulatory Managers and 12 staff personnel. The group works with field personnel to create and regularly review safety policies and procedures, in an effort to support continuous improvement of our SEMS. Our board of directors reviews our material safety metrics on a quarterly basis. Safety and Environmental metrics are incorporated into employee evaluations when determining compensation.

Benefits and Compensation

We pride ourselves on providing an attractive compensation and benefits program that allows our employees to view working at W&T as more than where they work, but a place where they may grow and develop. Our ability to succeed depends on recruiting and retaining top talent in the industry. We believe employees choose W&T in part due to our professional advancement opportunities, on the job training, engaging culture and competitive compensation and benefits.

As part of our compensation philosophy, we believe we must offer and maintain market competitive total rewards programs in order to attract and retain superior talent. These programs not only include base wages and incentives in support of our pay for performance culture, but also health and retirement benefits. We focus many programs on employee wellness. We believe these solutions help the overall health and wellness of our employees and help us successfully manage healthcare and prescription drug costs for our employee population.

Website Access to Company Reports

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments to those reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at *www.wtoffshore.com.* These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Form 10-K and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., 5718 Westheimer Road, Suite 700, Houston, Texas 77057 or by calling (713) 297-8024. Information on our website is not a part of this Form 10-K.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to us and our industry could materially impact our future performance and results of operations. We have provided below a list of known material risk factors that should be reviewed when considering buying or selling our securities. These are not all the risks we face, and other factors currently considered immaterial or unknown to us may impact our future operations.

Market and Competitive Risks

Oil, NGL and natural gas prices can fluctuate widely due to a number of factors that are beyond our control. Depressed oil, NGLs or natural gas prices adversely affect our business, financial condition, cash flow, liquidity or results of operations and could affect our ability to fund future capital expenditures needed to find and replace reserves, meet our financial commitments and to implement our business strategy.

The price we receive for our oil, NGLs and natural gas production directly affects our revenues, profitability, access to capital, ability to produce these commodities economically and future rate of growth. Historically, oil, NGLs and natural gas prices have been volatile and subject to wide price fluctuations in response to domestic and global changes in supply and demand, economic and legal forces, events and uncertainties, and numerous other factors beyond our control, including:

- general economic conditions and level of economic growth, including low or negative growth;
- changes in global supply and demand for oil, NGLs and natural gas;
- events that impact global market demand, such as a pandemic or other world health event;
- production quotas or other actions that might be imposed by OPEC+;
- the price and quantity of imports of foreign oil, NGLs, natural gas and liquefied natural gas into the U.S.;
- acts of war, terrorism or political instability in oil producing countries (e.g. the invasion of Ukraine by Russia and conflicts in the Middle East);
- domestic and foreign governmental regulations and taxes;
- U.S. federal, state and foreign government policies and regulations regarding current and future exploration and development of oil and gas;
- political conditions and events, including embargoes and moratoriums, affecting oil-producing activities;
- the level of domestic and global oil and natural gas exploration and production activities;
- the level of global oil, NGLs and natural gas inventories;
- adverse weather conditions and exceptional weather conditions, including severe weather events in the U.S. Gulf Coast;
- technological advances affecting energy consumption and the availability and cost of alternative energy sources;
- the price, availability and acceptance of alternative fuels;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- cyberattacks on our information infrastructure or systems controlling offshore equipment;
- activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize or eliminate future emissions of carbon dioxide, methane gas and other GHGs;
- the effect of energy conservation efforts;
- the availability of pipeline and other transportation alternatives and third-party processing capacity; and
- geographic differences in pricing.

Extended periods of lower prices for oil, NGLs and natural gas can have a material adverse impact on our results of operations, financial condition and liquidity. Among other things, our earnings, cash flows and capital expenditure programs could be negatively affected, as could our production and our estimates of proved reserves. A significant or sustained decline in liquidity could adversely affect our credit ratings, potentially increase financing costs and reduce access to capital markets. We may be unable to realize anticipated cost savings and expenditure reductions that are intended to compensate for such downturns. In addition, extended periods or low commodity prices can have a material adverse impact on the results of operations, financial condition and liquidity of our suppliers, vendors, partners and customers upon which our own results of operations and financial condition depends.

If oil, NGL and natural gas prices decrease from their current levels, we may be required to further reduce the estimated volumes and future value associated with our total proved reserves or record impairments to the carrying values of our oil and natural gas properties.

Lower future oil, NGLs and natural gas prices may reduce our estimates of the proved reserve volumes that may be economically recovered, which would reduce the total volumes and future value of our proved reserves. Under the full cost method of accounting for oil and gas producing activities, a ceiling test is performed at the end of each quarter to determine if our oil and gas properties have been impaired. Capitalized costs of oil and gas properties are generally limited to the present value of future net revenues of proved reserves based on the average price of the 12-month period prior to the ending date of each quarterly assessment using the unweighted arithmetic average of the first-day-of-the-month price for each month within such period. Impairments of our oil and gas properties are more likely to occur during prolonged periods of depressed oil, NGLs and natural gas pricing. While we have not recorded an impairment of our oil and gas properties during 2024, any further decreases in commodity pricing could cause an impairment, which would result in a non-cash charge to earnings.

Commodity derivative positions may limit our potential gains.

In order to manage our exposure to price risk in the marketing of our production, we have entered into commodity derivative positions with respect to a portion of our expected future production from natural gas, and may in the future enter into commodity derivative positions with respect to oil or natural gas. See *Financial Statements and Supplementary Data– Note 11 –Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information on our derivative contracts and transactions. While these commodity derivative positions are intended to reduce the effects of price volatility, they may also limit future income if prices were to rise substantially over the price established by such positions. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which there is a widening of price differentials between delivery points for our production and the delivery points assumed in the hedge arrangements or the counterparties to the derivative contracts fail to perform under the terms of the contracts.

Competition for oil and natural gas properties and prospects is intense; some of our competitors have larger financial, technical and personnel resources that may give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil, NGLs and natural gas and securing trained personnel. Many of our competitors have financial resources that allow them to obtain substantially greater technical expertise and personnel than we have. We actively compete with other companies in our industry when acquiring new leases or oil and natural gas properties. For example, new leases acquired from the BOEM are acquired through a “sealed bid” process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more to acquire productive oil and natural gas properties and exploratory prospects than we are able or willing to pay or finance. Finally, companies with larger financial resources may have a significant advantage in terms of meeting any potential new bonding requirements. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production. The marketability of our production depends mostly upon the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and processing facilities, which in some cases are owned by third parties.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities, which in some cases are owned and operated by third parties.

We also depend upon third-party pipelines that provide delivery options from our facilities. Because we do not own or operate these pipelines, their continued operation is not within our control. These pipelines may become unavailable for a number of reasons, including testing, maintenance, capacity constraints, accidents, government regulation, weather-related events or other third-party actions. If any of these third-party pipelines become partially or fully unavailable to transport oil and natural gas, or if the gas quality specification for the natural gas pipelines changes so as to restrict our ability to transport natural gas on those pipelines, our revenues could be adversely affected.

A portion of our oil and natural gas is processed for sale on platforms owned by third parties with no economic interest in our wells and no other processing facilities would be available to process such oil and natural gas without significant investment by us. In addition, third-party platforms could be damaged or destroyed by tropical storms, hurricanes or other weather events, which could reduce or eliminate our ability to market our production. As of December 31, 2024, four fields, accounting for approximately 3.7 MMBoe (or 2.9%) of our total proved reserves, are tied back to separate, third-party owned platforms. Although we have entered into contracts for the process of our production with the owners of such platforms, there can be no assurance that the owners of such platforms will continue to process our oil and natural gas production.

In recent years, we have seen a consolidation of gathering systems, pipelines and processing facilities in the Gulf of America, which has led to fewer midstream counterparties to contract with for transportation and processing. As part of these consolidation efforts, we have also seen a decommissioning of midstream assets. A reduction in the number of potential midstream counterparties and available midstream infrastructure could negatively impact our ability to market production.

If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.

If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserve estimates and potential impairments and associated charges to our earnings. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut-in. Any shut-in or curtailment of the oil, natural gas and NGLs produced from our fields could adversely affect our financial condition and results of operations.

In addition, we may be required to shut in wells because of a reduction in demand for our production or because of inadequacy or unavailability of pipelines, gathering system capacity or processing facilities. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to process or deliver our production to market. For example, the government recently issued an order requiring the abandonment of certain facilities in the Gulf of America, rendering the pipelines and other midstream assets that cross that facility incapable of operating. Our production from certain properties currently utilizes a pipeline that crosses over the facility in order for our production to reach its eventual market and, as a result of the government’s order to abandon the facilities, we are required to shut-in our production at the affected properties until we can find an alternative path to market for such production. While we are working to find an alternative path to market, we are unable to realize revenues from our production at the affected properties until such time as an alternative arrangement is made.

Operating Risks

Production periods and relatively short reserve lives for our Gulf of America properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil, NGL and natural gas prices.

All of our current production is from the Gulf of America. Proved reserves in the Gulf of America generally have shorter reserve lives than proved reserves in many other producing regions of the United States, in part due to the difference in rules related to booking PUDs between conventional and unconventional basins. Our independent petroleum consultant estimates that 36.4% of our total proved reserves as of December 31, 2024 will be depleted within three years. As a result, our need to replace proved reserves and production from new investments is relatively greater than that of producers who recover lower percentages of their proved reserves over a similar time period, such as those producers who have a larger portion of their proved reserves in areas other than the Gulf of America.

Exploring for, developing or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop or acquire additional reserves or make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. Our need to generate revenues to fund ongoing capital commitments or repay debt may limit our ability to slow or shut-in production from producing wells during periods of low prices for oil and natural gas. We cannot assure you that our future exploitation, exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Further, current market conditions may adversely impact our ability to obtain financing to fund acquisitions, and further lower the level of activity and depressed values in the oil and natural gas property sales market.

We are not insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational loss-related events. We currently carry multiple layers of insurance coverage in our Energy Package, covering our operating activities, with higher limits of coverage for higher valued properties and wells. Our insurance coverage includes deductibles that have to be met prior to recovery, as well as sub-limits or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences, damages or losses. See Part I, Item 1. *Business – Insurance Coverage* for more information on our insurance coverage.

In the past, tropical storms and hurricanes in the Gulf of America have caused catastrophic losses and property damage. Similar events may cause damage or liability in excess of our coverage that might severely impact our financial position. We may be liable for damages from an event relating to a project in which we own a non-operating working interest. Well control insurance coverage becomes limited from time to time and the cost of such coverage becomes both more costly and more volatile. In the past, we have been able to renew our policies each annual period, but our coverage has varied depending on the premiums charged, our assessment of the risks and our ability to absorb a portion of the risks. The insurance market may further change dramatically in the future due to severe storm damage, major oil spills or other events.

Such events as noted above may also cause a significant interruption to our business, which might also severely impact our financial position. We may experience production interruptions for which we do not have business interruption insurance.

We re-evaluate the purchase of insurance, policy limits and terms annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. The occurrence of a significant event for which our losses are not fully insured or indemnified, or for which the insurance companies will not pay our claims, could have a material adverse effect on our financial condition and results of operations.

In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. Currently the OPA requires owners and operators of offshore oil production facilities to have ready access to between $35.0 million and $150.0 million, which amount is based on a worst case oil spill discharge volume demonstration that can be used to cover costs that could be incurred in responding to an oil spill at our facilities on the OCS. We are currently required to demonstrate that we have ready access to $70.0 million. If OPA is amended to increase the minimum level of financial responsibility, we may experience difficulty in providing financial assurances sufficient to comply with this requirement.

We conduct exploration, development and production operations on the deep shelf and in the deepwater of the Gulf of America, which presents unique operating risks.

The deep shelf and the deepwater of the Gulf of America are areas that have had less drilling activity due, in part, to their geological complexity, depth and higher cost to drill and ultimately develop. There are additional risks associated with deep shelf and deepwater drilling that could result in substantial cost overruns and/or result in uneconomic projects or wells. Deeper targets are more difficult to interpret with traditional seismic processing. Moreover, drilling costs and the risk of mechanical failure are significantly higher because of the additional depth and adverse conditions, such as high temperature and pressure. For example, the drilling of deepwater wells requires specific types of rigs with significantly higher day rates as compared to the rigs used in shallower water, sophisticated sea floor production handling equipment, expensive state-of-the-art platforms and infrastructure investments. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. In addition, due to the significant time requirements involved with exploration and development activities, particularly for wells in the deepwater or wells not located near existing infrastructure, actual oil and natural gas production from new wells may not occur, if at all, for a considerable period of time following the commencement of any particular project. Accordingly, we cannot provide assurance that our oil and natural gas exploration activities in the deep shelf, the deepwater and elsewhere will be commercially successful.

We may not be in a position to control the timing of development efforts, associated costs or the rate of production of the reserves from our non-operated properties.

As of December 31, 2024, we operate 86.1% of our wells. As we carry out our drilling program, we may not serve as operator of all planned wells. In that case, we have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners and our limited ability to influence operations and associated costs of properties operated by others could prevent the realization of anticipated results in drilling or acquisition activities.

We are subject to numerous risks inherent to the exploration and production of oil and natural gas.

Oil and natural gas exploration and production activities involve certain risks that a combination of experience, knowledge and careful evaluation may not be able to overcome. Our future success will depend on the success of our exploration and production activities and on the future existence of the infrastructure and technology that will allow us to take advantage of our findings. Additionally, our properties are located in deepwater, which generally increases the capital and operating costs, technical challenges and risks associated with exploration and production activities. As a result, our exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected production from our prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of oil and natural gas prices, proximity, capacity and availability of pipelines, the availability of processing facilities, equipment availability and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, importing and exporting of hydrocarbons, environmental, safety, health and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

We are subject to drilling and other operational hazards.

The exploration, development and production of oil and gas properties involves a variety of operating risks, including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, pipeline ruptures or discharges. Additionally, our offshore operations are subject to the additional hazards of marine operations, such as capsizing, collisions and adverse weather and sea conditions, including the effects of tropical storms, hurricanes and other weather events.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations and production, repairs to resume operations and loss of reserves. Any of these industry operating risks could have a material adverse effect on our business, results of operations and financial condition.

The geographic concentration of our properties in the Gulf of America subjects us to an increased risk of loss of revenues or curtailment of production from factors specifically affecting the Gulf of America, including hurricanes.

The geographic concentration of our properties along the U.S. Gulf Coast and adjacent waters on and beyond the OCS means that some or all of our properties could be affected by the same event should the Gulf of America experience severe weather, including tropical storms and hurricanes; delays or decreases in production, the availability of equipment, facilities or services; changes in the status of pipelines that we depend on for transportation of our production to the marketplace; delays or decreases in the availability of capacity to transport, gather or process production; and changes in the regulatory environment.

Because a majority of our properties could experience the same conditions at the same time, these conditions could have a greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area.

A significant portion of our production, revenue and cash flow is concentrated in our Mobile Bay Properties. Because of this concentration, any production problems, impacts of adverse weather or inaccuracies in reserve estimates could have a material adverse impact on our business.

For 2024, approximately 35% of our production and 15% of our total revenue was attributable to our interests in certain oil and natural gas leasehold interests and associated wells and units located off the coast of Alabama, in state coastal and federal Gulf of America waters approximately 70 miles south of Mobile, Alabama (the “Mobile Bay Properties”). This concentration means that any impact on our production from this field, whether because of mechanical problems, adverse weather, well containment activities, changes in the regulatory environment or otherwise, could have a material adverse effect on our business. During 2024, our Mobile Bay Properties were shut-in for various reasons, including Hurricane Helene, compressor problems and downstream operated plant issues. These shut-ins resulted in deferred production of approximately 850 MBoe based on production rates prior to the shut-ins. Any additional shut-ins, depending on the duration of the shut-in, could have a material adverse impact on our business. In addition, if the actual reserves associated with the Mobile Bay Properties are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and that may in the future, allow them to implement new technologies before we can. We rely heavily on the use of advanced seismic technology to identify exploitation opportunities and to reduce our geological risk. Seismic technology or other technologies that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

Estimates of our proved reserves depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in the estimates or underlying assumptions will materially affect the quantities of and present value of future net revenues from our proved reserves. Our actual recovery of reserves may substantially differ from our estimated proved reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of our reserves at December 31, 2024.

In order to prepare our year-end reserve estimates, our independent petroleum consultant projected our production rates and timing of development expenditures. Our independent petroleum consultant also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be under our control. The process also requires economic assumptions about matters such as oil and natural gas prices, operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the standardized measure or the present value of future net revenues from our proved oil and natural gas reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month unweighted first-day-of-the-month average price for each product and costs in effect on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

At December 31, 2024, approximately 17% of our estimated proved reserves (by volume) were undeveloped. Any or all of our PUD reserves may not be ultimately developed or produced or may not be ultimately produced during the time periods we plan or at the costs we budget, which could result in the write-off of previously recognized reserves. Recovery of PUD reserves generally requires significant capital expenditures and successful drilling or waterflood operations. Our reserve estimates include the assumptions that we incur capital expenditures to develop these undeveloped reserves and the actual costs and results associated with these properties may not be as estimated. Any material inaccuracies in these reserve estimates or underlying assumptions materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Prospects that we decide to drill may not yield oil or natural gas in commercial quantities or quantities sufficient to meet our targeted rates of return.

A prospect is an area in which we own an interest, could acquire an interest or have operating rights, and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic accumulations of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial seismic data processing and interpretation, which will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. Sustained low oil, NGLs and natural gas pricing may also significantly impact the projected rates of return of our projects without the assurance of significant reductions in costs of drilling and development. To the extent we drill additional wells in the deepwater and/or on the deep shelf, our drilling activities could become more expensive. In addition, the geological complexity of deepwater and deep shelf formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, we can offer no assurance that we will find commercial quantities of oil and natural gas and, therefore, we can offer no assurance that we will achieve positive rates of return on our investments.

We may not realize all of the anticipated benefits from our future acquisitions.

We expect to grow by expanding the exploitation and development of our existing assets, in addition to making targeted acquisitions in the Gulf of America. We may not realize all of the anticipated benefits from future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including higher than expected acquisition and operating costs or other difficulties, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices. This could lead to potential adverse short-term or long-term effects on our operating results.

Our future acquisitions and divestitures could expose us to potentially significant liabilities, including plugging and abandonment and decommissioning liabilities.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental, regulatory and other liabilities, including plugging and abandonment and decommissioning liabilities. Such assessments are inexact and may not disclose all material issues or liabilities. In connection with our assessments, we also perform a review of the acquired properties. However, such a review may not reveal all existing or potential problems. Additionally, such review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may be successful in obtaining contractual indemnification for preclosing liabilities, including environmental liabilities, but we expect that we will generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. In addition, even if we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and could potentially expose us to unindemnifiable liabilities, which could materially adversely affect our production, revenues and results of operations.

Our operations could be adversely impacted by security breaches, including cybersecurity breaches, which could affect the systems, processes and data needed to run our business.

We rely on our information technology (“IT”) infrastructure and management information systems to operate and record aspects of our business. Although we take security measures to protect against cybersecurity risks, including unauthorized access to our confidential and proprietary information, our security measures may not be able to detect or prevent every attempted breach. Similar to other companies, we have experienced cyber-attacks, although we have not suffered any material losses related to such attacks. Security breaches include, among other things, illegal hacking, computer viruses, interference with treasury function, theft or acts of vandalism or terrorism. A breach could result in an interruption in our operations, malfunction of our platform control devices, disabling of our communication links, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, violation of privacy or other laws and exposure to litigation. Any of these security breaches could have a material adverse effect on our consolidated financial position, results of operations and cash flows. The invasion of Ukraine by Russia, and the impact of world sanctions against Russia and the potential for retaliatory acts from Russia, could result in increased cybersecurity attacks against U.S. companies.

The loss of members of our senior management could adversely affect us.

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management could have a negative impact on our operations. We do not maintain or plan to obtain for the benefit of the Company any insurance against the loss of any of these individuals. See our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K for more information regarding our senior management team.

There may be circumstances in which the interests of significant stockholders could conflict with the interests of our other stockholders.

Our CEO owns a significant portion of our common stock. Circumstances may arise in which he may have an interest in pursuing or preventing acquisitions, divestitures, hostile takeovers or other transactions, or conflicts of interest could arise in the future regarding, among other things, decisions related to our financing, capital expenditures and business plans, or the pursuit of certain business opportunities, including the payment of dividends or the issuance of additional equity or debt, that, in his judgment, could enhance his investment in us or in another company in which he invests.

Such circumstances or conflicts might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership and lender relationships may adversely affect the trading price of our common stock because investors may perceive disadvantages in owning shares in companies with significant stockholder concentrations or with such potential conflicts.

Capital Risks

Our debt level could negatively affect our financial condition, results of operations and business prospects.

As of December 31, 2024, we had $399.1 million of principal amount of long-term debt outstanding. Our level of indebtedness has important consequences on our operations, including:

- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to fund future working capital requirements, capital expenditures and ARO, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets;
- requiring that we dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt obligations, thereby reducing the availability of cash flow for funding future working capital requirements, capital expenditures and ARO obligations, engaging in future acquisitions or development activities or otherwise realizing the value of our assets;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- limiting or impairing our ability to obtain additional financing or refinancing in the future or requiring us to seek alternative financing, which may be more restrictive or expensive; and
- placing us at a competitive disadvantage compared to our competitors that have less debt.

We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt or otherwise meet our future obligations. In such scenarios, we may be required to refinance all or part of our existing debt, sell assets, reduce capital expenditures, obtain new financing or issue equity. However, we may not be able to accomplish any of these transactions on terms acceptable to us or such actions may not yield sufficient capital to meet our obligations. Any of the above risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our debt agreements contain restrictions that limit our abilities to incur certain additional debt or liens or engage in other transactions, which could limit growth and our ability to respond to changing conditions.

In January 2025, we issued $350.0 million in aggregate principal amount of our 10.75% Senior Second Lien Notes due 2029 (the "10.75% Notes") and entered into a new credit agreement with initial bank lending commitments of $50.0 million with a letter of credit sublimit of $10.0 million (the "New Credit Agreement"). The indenture (the "2025 Indenture") governing our 10.75% Notes and our New Credit Agreement contain a number of significant restrictive covenants in addition to covenants restricting the incurrence of additional debt. These covenants limit our ability and the ability of certain subsidiaries, among other things, to:

- make loans and investments;
- incur or guarantee additional indebtedness;
- create certain liens;

- transfer or sell assets;
- enter into agreements that restrict dividends or other payments from our subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of the Company;
- enter into transactions with our affiliates;
- pay dividends or make other distributions on capital stock or subordinated indebtedness; and
- create subsidiaries that would not be restricted by the covenants of the 2025 Indenture.

Our New Credit Agreement requires us, among other things, to maintain certain financial ratios and satisfy certain financial condition tests. These restrictions may also limit our ability to obtain future financings, withstand a future downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us from the restrictive covenants under our 2025 Indenture and our New Credit Agreement.

A breach of any covenant in the agreements governing our debt would result in a default under such agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the debt outstanding under such agreement and in a default with respect to, and acceleration of, the debt outstanding under any other debt agreements. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to make all of the required payments or borrow sufficient funds to refinance such accelerated debt. Even if new financing were then available, it may not be on terms that are acceptable to us.

We have significant capital needs to conduct our operations and replace our production, and our ability to access the capital and credit markets to raise capital or refinance our existing indebtedness on favorable terms may be limited by industry conditions and financial markets.

We spend a substantial amount of capital for the acquisition, exploration, exploitation, development, and production of oil and natural gas reserves. We fund our capital expenditures primarily through operating cash flows and cash on hand. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment and regulatory, technological and competitive developments. A further reduction in commodity prices may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

If low oil and natural gas prices, operating difficulties, declines in reserves or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditure program. After utilizing our available sources of financing, we may be forced to raise additional debt or equity to fund such capital expenditures.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Volatility in the energy sector, together with the higher interest rate environment, has caused and may continue to cause lenders to increase the interest rates under our credit facilities, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers.

If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

If we default on our secured debt, the value of the collateral securing our secured debt may not be sufficient to ensure repayment of all of such debt.

Our New Credit Agreement and our 10.75% Notes are secured by various liens on our oil and natural gas properties. Any future borrowings under our New Credit Agreement would be secured on a first priority basis by the assets securing the 10.75% Notes. If the proceeds of the sale of the collateral securing the 10.75% Notes or any future indebtedness incurred under the New Credit Agreement are not sufficient to repay all amounts due in respect of such debt, then claims against our remaining assets to repay any amounts still outstanding under our secured obligations would be unsecured, and our ability to pay our other unsecured obligations and any distributions in respect of our capital stock would be significantly impaired.

With respect to some of the collateral securing our debt, any collateral trustee's security interest and ability to foreclose on the collateral will also be limited by the need to meet certain requirements, such as obtaining third-party consents, paying court fees that may be based on the principal amount of the parity lien obligations and making additional filings. If we are unable to obtain these consents, pay such fees or make these filings, the security interests may be invalid, and the applicable holders and lenders will not be entitled to the collateral or any recovery with respect thereto. These requirements may limit the number of potential bidders for certain collateral in any foreclosure and may delay any sale, either of which events may have an adverse effect on the sale price of the collateral.

We may not be able to repurchase the 10.75% Notes upon a change of control.

If we experience certain kinds of changes of control, we must give holders of the 10.75% Notes the opportunity to sell us their notes at 101% of their principal amount, plus accrued and unpaid interest. However, in such an event, we might not be able to pay the holders the required repurchase price for the notes they present to us because we might not have sufficient funds available at that time, or the terms of our New Credit Agreement or other agreements we may enter into in the future may prevent us from applying funds to repurchase the 10.75% Notes. The source of funds for any repurchase required as a result of a change of control will be our available cash or cash generated from our oil and gas operations or other sources, including:

- borrowings under the New Credit Agreement or other sources;
- sales of assets; or
- sales of equity.

Finally, using available cash to fund the potential consequences of a change of control may impair our ability to obtain additional financing in the future, which could negatively impact our ability to conduct our business operations.

We may be required to post cash collateral pursuant to our agreements with sureties under our existing or future bonding arrangements, which could 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 agreements with various sureties under our existing bonding arrangements, or under any future bonding arrangements we may enter into, we may be required to post collateral. Additional collateral would likely be in the form of cash or letters of credit. We cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for future bonds.

On August 14, 2024, we filed a complaint seeking declaratory relief (the "Original Complaint") in the U.S. District Court for the Southern District of Texas, Houston Division, against Endurance Assurance Corporation and Lexon Insurance Company (the "Sompo Sureties"), providers of government-required surety bonds that secure decommissioning obligations we may have with respect to certain of our oil and natural gas assets (the "Sompo Sureties Litigation"). As described in the Original Complaint, we have paid all negotiated premiums associated with the bonds issued by the Sompo Sureties prior to the Original Complaint and have not suffered a material change to our financial status. Despite this, the Sompo Sureties issued us written demands requesting we provide collateral to the Sompo Sureties. On October 9, 2024, the Sompo Sureties filed an answer and counterclaim alleging breach of contract due to our failure to provide the collateral demanded by the Sompo Sureties. The Sompo Sureties originally issued approximately $55.0 million in surety bonds on our behalf. However, the BOEM cancelled a $13.1 million bond after we fulfilled our decommissioning obligations. Despite this, the Sompo Sureties have requested approximately $55.0 million in cash collateral.

On October 21, 2024, U.S. Specialty Insurance Company ("USSIC") filed a petition in the District Court of Harris County, Texas, alleging, among other things, breach of the indemnity agreement between USSIC and us and seeking to compel us to provide the collateral demanded by USSIC (the "USSIC Litigation"). On October 25, 2024, we filed a notice of removal with the District Court of Harris County, Texas, removing the case to U.S. District Court for the

Southern District of Texas, Houston Division. USSIC has issued approximately $111.0 million in surety bonds on our behalf and has requested $23.0 million in cash collateral.

On November 8, 2024, Pennsylvania Insurance Company a/k/a Applied Surety Underwriters ("Applied") filed a petition in the United States District Court for the Southern District of Texas, Houston Division, alleging, among other things, breach of the indemnity agreement between Applied and us and seeking to compel us to provide the collateral demanded by Applied and unpaid premiums of approximately $0.4 million (the "Applied Litigation"). Applied issued approximately $11.3 million in surety bonds on our behalf and has requested approximately $11.3 million in cash collateral.

Also on November 8, 2024, United States Fire Insurance Company ("U.S. Fire" and, together with the Sompo Sureties, USSIC and Applied, the "Sureties") filed a petition in the United States District Court for the Southern District of Texas, Houston Division, alleging, among other things, breach of the indemnity agreement between U.S. Fire and us and seeking to compel us to provide the collateral demanded by U.S. Fire (the "U.S. Fire Litigation"). U.S. Fire claims to have issued approximately $93.5 million in surety bonds on our behalf and has requested approximately $93.5 million in cash collateral.

The Sureties' aggregate collateral demands against us total approximately $183.7 million. In addition, Philadelphia Indemnity Insurance Company ("PIIC") separately made a collateral demand of $71.0 million. No legal action has been filed by PIIC as of the date hereof. The total aggregate collateral demanded by the Sureties and PIIC is approximately $254.7 million (the "Demanded Collateral").

On November 22, 2024, the court consolidated the Sompo Sureties Litigation, USSIC Litigation, the Applied Litigation, and the U.S. Fire Litigation (as consolidated, the "Sureties Litigation"). On December 11, 2024, as a result of the foregoing, we filed an amended complaint (the Original Complaint, as amended, the "Complaint") against the Sureties. The Complaint, in relevant part, seeks declaratory relief that (1) the Sureties may not enforce their indemnity agreements such that their action constitute an abuse of right; (2) the Sureties' interpretation of the indemnity agreements render the agreements illusory; (3) the Sureties may not make unreasonable demands for collateral; (4) the Sureties must accept reasonable collateral as offered by us; (5) no additional collateral is required of us; (6) the Sureties may not make joint demands for collateral that are inconsistent with those of each other such that we cannot comply with each demand; and (7) the Sureties' changed business model are not legitimate grounds to demand further collateral beyond that offered by us. We further assert the following counterclaim against the Sureties: (1) violations of the Sherman Antitrust Act; (2) violations of the Texas Free Enterprise and Antitrust Act; (3) violations of the Texas Insurance Code Section 541; (4) tortious interference with existing contracts and prospective business relationships; and (5) conspiracy.

As a result of the Sureties Litigation, we may potentially be required to provide some or all of the Demanded Collateral, or we may be required to or choose to replace the surety bonds provided by the applicable surety with alternate bonding or financial assurance. All of the parties to the Sureties Litigation, as well as PIIC (who is not a party to the Sureties Litigation) agreed to mediate the dispute on February 14, 2025, until the mediator declares an impasse. We are seeking to negotiate a reasonable resolution with respect to collateral provision amongst the Sureties and other surety entities with conflicting or different collateral requests (such as PIIC). As of March 4, 2025, the mediation continues to be ongoing.

To the extent that the Sureties succeed in forcing us to fulfill the Demanded Collateral, or in the event that other surety entities attempt to do the same, the fulfilment of such demands could be significant and our liquidity position will 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; unable to execute our ARO plan; or unable to comply with our existing debt instruments.

Legal, Government and Regulatory Risks

We are subject to numerous environmental, health and safety regulations which are subject to change and may also result in material liabilities and costs.

Our operations are subject to U.S. federal, state and local environmental, health and safety laws and regulations governing, among other things, the emission and discharge of pollutants into the environment, the generation, storage, handling, use and transportation of toxic and hazardous wastes and the health and safety of our employees. Our operations in the Gulf of America require permits from federal and state governmental agencies in order to perform drilling and completion activities and conduct other regulated activities. There is a risk that we have not been or will not be at all times in complete compliance with these permits and the environmental laws and regulations to which we are subject. Any failure by us to comply with applicable environmental laws and regulations may result in governmental authorities taking action against us that could adversely impact our operations and financial condition, including the:

- issuance of administrative, civil and criminal penalties;
- denial or revocation of permits or other authorizations;
- imposition of limitations on our operations; and
- performance of site investigatory, remedial or other corrective actions.

If we fail to obtain permits in a timely manner or at all (for example, due to opposition from community or environmental groups, government delays, changes in laws or the interpretation thereof, or any other reason), such failure could impede our operations, which could have a material adverse effect on our results of operations and our financial condition.

The longer-term trend of more expansive and stringent environmental legislation and regulations is expected to continue, which makes it challenging to predict the cost or impact on our future operations. Liabilities associated with environmental matters could have a material adverse effect on our business, financial condition and results of operations. Under certain environmental laws, we could be exposed to strict, joint and several liability for cleanup costs and other damages relating to releases of hazardous materials or contamination, regardless of whether we were responsible for the release or contamination, and even if our operations were lawful or in accordance with industry standards at the time.

Additional changes in environmental laws, regulations, guidelines or enforcement interpretations could require us to devote capital or other resources to comply with those laws and regulations. These changes could also subject us to additional costs and restrictions, including increased fuel costs. In addition, such changes in laws or regulations could increase the costs of compliance and doing business for our customers and thereby decrease the demand for our services.

New laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement could significantly increase our capital expenditures and operating costs or could result in delays, limitations or cancelations to our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. See *Business – Other Regulation of the Oil and Natural Gas Industry* under Part I, Item 1 in this Form 10-K for a more detailed description of our environmental regulations.

We may be unable to provide financial assurances in the amounts and under the time periods required by the BOEM if the BOEM submits future demands to cover our decommissioning obligations.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities in the OCS. In April 2024, BOEM released a final rule that changes the way BOEM evaluates the financial health of companies and offshore assets in setting financial assurance requirements. Under the new rule, BOEM streamlined the criteria used to evaluate the financial health of an energy company down to two factors: (i) the company's credit rating, and (ii) the ratio of the value of the company's proved reserves to decommissioning liability associated with those reserves. The new rule also codifies the usage of BSEE decommissioning estimates to evaluate supplemental financial assurance requirements and allows third party guarantors (upon agreement with BOEM) to provide limited guarantees to specific amounts or specific leases instead of the blanket guarantees that have been used in the past. Finally, the new rule also requires a base financial assurance requirement of $500,000 for federal RUEs to match the requirement for state RUEs. To provide the industry with flexibility to meet the new financial assurance requirements, BOEM will allow current lessees and grant holders to request phased-in payments over a three-year period. BOEM estimates that the industry will be required to provide $6.9 billion in new financial assurances under the new rule, which took effect on June 29, 2024. Following the announcement of the new rule, a series of lawsuits from both states and industry groups have been filed against BOEM to block the implementation of the new rule. We are actively monitoring ongoing litigation with respect to the new rule.

If we fail to comply with the new rule and such future orders, the BOEM could commence enforcement proceedings or take other remedial action against us, including assessing civil penalties, suspending operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition. In addition, if we are required to provide collateral in the form of cash or letters of credit, our liquidity position could 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.

Additionally, as a result of adverse developments in restructuring and bankruptcies of companies operating in the OCS, many surety companies have left the offshore surety market or greatly decreased their participation in the offshore surety market, which has materially reduced the availability of surety bonds for projects in the OCS and may reduce the ability of companies operating in the OCS to obtain bonding without posting collateral. As a result, bonding may not be available to us on commercially reasonable terms, which may lead to significantly increased costs on our operations. Further, there may not be sufficient surety bond capacity available for companies in the OCS which could consequently have a material adverse effect on our ability to conduct operations.

All of these factors may make it more difficult for us to obtain the financial assurances required by the BOEM to conduct operations in the OCS. We cannot predict what actions President Trump may take regarding these regulations or the timing thereof or the availability of surety bonds on commercially reasonable terms in the marketplace. There is significant uncertainty with respect to the financial assurance regulatory requirements and current market availability of surety bonds. These and other changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations and consequently have a material adverse effect on our business and results of operations.

Additional deepwater drilling laws, regulations and other restrictions, delays and other offshore-related developments in the Gulf of America may have a material adverse effect on our business, financial condition, or results of operations.

The Biden administration took a number of actions that had potential to result in stricter environmental, health and safety standards applicable to our operations and those of the oil and natural gas industry more generally. Issuance of new or amended rulemakings restricting deepwater leasing, permitting or drilling could result in more stringent or costly restrictions, delays or cancellations to our operations as well as those of similarly situated offshore energy companies on the OCS. Compliance with any added or more stringent regulatory requirements or enforcement initiatives and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions by governmental agencies, delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans and possible additional regulatory initiatives, could adversely affect or delay new drilling and ongoing development efforts.

Moreover, if material spill incidents were to occur in the future, the United States could elect to issue directives to temporarily cease drilling activities and, in any event, issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. Since taking office in January 2025, President Trump has expressed support for an expansion of offshore oil and natural gas drilling and has taken executive action to rescind several Biden-era restrictions on OCS leasing for oil and natural gas exploration and development. See Part I, Item 1. *Business – Environmental, Health and Safety Matters and Regulations* and *Other Regulation of the Oil and Natural Gas Industry* for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry.

Our estimates of future ARO may vary significantly from period to period, and unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We are required to record a liability for the present value of our ARO to plug and abandon inactive non-producing wells, to remove inactive or damaged platforms, and inactive or damaged facilities and equipment, collectively referred to as “idle iron,” and to restore the land or seabed at the end of oil and natural gas production operations. An existing BSEE NTL describes the obligations of offshore operators to timely decommission idle iron by means of abandonment and removal. Pursuant to these idle iron NTL requirements, BSEE issued us letters, directing us to plug and abandon certain wells that the agency identified as no longer capable of production in paying quantities by specified timelines. In response, we are currently evaluating the list of wells proposed as idle iron by BSEE and currently anticipate that those wells determined to be idle iron will be decommissioned by the specified timelines or at times as otherwise determined by BSEE following further discussions with the agency. While we have established AROs for well decommissioning, additional AROs, significant in amount, may be necessary to conduct plugging and abandonment of the wells designated in the future as idle iron, but we do not expect the costs to plug and abandon such additional wells will have a material effect on our financial condition, results of operations or cash flows. Nevertheless, these decommissioning activities are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths, and there exists the possibility that increased liabilities beyond what we established as AROs may arise and the pace for completing these activities could be adversely affected by idle iron decommissioning activities being pursued by other offshore oil and gas lessees that may also have received similar BSEE directives, which could restrict the availability of equipment and experienced workforce necessary to accomplish this work.

Estimating future restoration and removal costs in the Gulf of America is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or such requirements may be interpreted more restrictively, and asset removal technologies are constantly evolving, which may result in additional, increased or decreased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. For example, because we operate in the Gulf of America, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes and other adverse weather conditions. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future ARO could differ dramatically from what we may ultimately incur as a result of damage from a hurricane or other natural disaster. Additionally, a sustained lower commodity price environment may cause our non-operator partners to be unable to pay their fair share of costs, which may require us to pay our proportionate share of the defaulting party’s share of costs.

We have divested, as assignor, various leases, wells and facilities located in the Gulf of America where the purchasers, as assignees, typically assume all abandonment obligations acquired. Certain of these counterparties in these divestiture transactions or third parties in existing leases have filed for bankruptcy protection or undergone associated reorganizations and may not be able to perform required abandonment obligations. Under certain circumstances, regulations or federal laws, such as the OCSLA, could impose joint and several strict liability and require predecessor assignors, such as us, to assume such obligations. As of December 31, 2024, we have $22.6 million of loss contingency recorded related to anticipated decommissioning obligations. See Part II, Item 8. *Financial Statements and Supplementary Data — Note 6 — Commitments and Contingencies* for more information.

We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration, development, production and transportation of oil and natural gas and operational safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with such legal requirements may harm our business, results of operations and financial condition.

Our operations could be significantly delayed or curtailed, and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. Regulated matters include lease permit restrictions; limitations on our drilling activities in environmentally sensitive areas, such as marine habitats, and restrictions governing the discharge of materials into the environment; bonds or other financial responsibility requirements to cover drilling contingencies and well decommissioning costs; the spacing of wells; operational reporting; reporting of natural gas sales for resale; and taxation. Under these laws and regulations, we could be liable for personal injuries, property and natural resource damages, well site reclamation costs, and governmental sanctions, such as fines and penalties.

Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our results of operations and financial condition, as well as the market price of our common stock. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. See *Business – Environmental, Health and Safety Matters and Regulations* and *Other Regulation of the Oil and Natural Gas Industry* under Part I, Item 1 in this Form 10-K for a more detailed explanation of regulations impacting our business.

We are subject to laws, rules, regulations and policies regarding data privacy and security. Many of these laws and regulations are subject to change and reinterpretation, and could result in claims, changes to our business practices, monetary penalties, increased cost of operations or other harm to our business.

We are subject to a variety of federal, state and local laws, directives, rules and policies relating to data privacy and cybersecurity. The regulatory framework for data privacy and cybersecurity worldwide is continuously evolving and developing, and, as a result, interpretation and implementation standards and enforcement practices are likely to remain uncertain for the foreseeable future. It is also possible that inquiries from governmental authorities regarding cybersecurity breaches increase in frequency and scope. These data privacy and cybersecurity laws also are not uniform, which may complicate and increase our costs for compliance. Any failure or perceived failure by us or our third-party service providers to comply with any applicable laws relating to data privacy and cybersecurity, or any compromise of security that results in the unauthorized access, improper disclosure, or misappropriation of data, could result in significant liabilities and negative publicity and reputational harm, one or all of which could have an adverse effect on our reputation, business, financial condition and operations.

The Inflation Reduction Act of 2022 could accelerate the transition to a low carbon economy and could impose new costs on our operations.

The IRA contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and carbon capture and sequestration, amongst other provisions. In addition, the IRA imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. The IRA amends the federal CAA to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. In January 2024, the EPA proposed a rule implementing the IRA's methane emissions charge. Under this rule, finalized in November 2024, the methane emissions charge was established at $900 per ton emitted over annual methane emissions thresholds, and would increase to $1,200 in 2025, and $1,500 for 2026 and each year after. In February 2025, Congress filed a resolution under the Congressional Review Act to repeal the methane emissions charge.

Calculation of the fee is based on certain thresholds established in the IRA. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives. This could decrease demand for oil and natural gas, increase our compliance and operating costs and consequently adversely affect our business.

We are subject to risks arising from climate change, including risks related to energy transition, which could result in increased costs and reduced demand for the oil and natural gas we produce and physical risks which could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

President Biden made addressing the threat of climate change from GHG emissions a priority under his administration, and regulatory agencies under the Biden administration issued rules in support of President Biden's regulatory and political agenda, which included reducing dependence on, and use of, fossil fuels and curtailment of hydraulic fracturing on federal lands. Since taking office in January 2025, President Trump has taken actions to reverse many of these Biden-era rules and policies. President Trump in January 2025 issued additional executive orders aimed at boosting fossil fuels and undoing Biden-era initiatives to limit GHG emissions. He declared a national energy emergency and revoked many of Biden's executive orders on climate change. New orders instruct agencies to roll back restrictions on offshore drilling and reconsider protections for Alaska's Arctic National Wildlife Refuge. President Trump also issued a moratorium on new wind power projects on federal lands, pausing new leases and permits for both onshore and offshore wind farms. He revoked an executive order that compelled government regulators to assess the risks of climate change to the financial system and he instructed agencies to review any regulations that might "burden the development of domestic energy resources." That could include major Biden administration climate policies, including EPA rules limiting emissions from coal- and natural gas-fired power plants and new fees on methane emissions from the oil and gas industry.

Nonetheless, our operations remain subject to a series of climate-related transition risks, including regulatory, political and litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs. See Part I, Item 1. *Business – Other Regulation of the Oil and Natural Gas Industry* for more discussion on the threat of climate change and restriction of GHG emissions.

The adoption and implementation of any international, federal, regional or state legislation, executive actions, regulations, policies or other regulatory initiatives that impose more stringent standards for GHG emissions on our operations or in areas where we produce oil and natural gas could result in increased compliance costs or costs of consuming fossil fuels, and thereby reduce demand for the oil and natural gas that we produce. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding climate change and environmental and sustainability matters. Activism could materially and adversely impact our ability to operate our business and raise capital. The foregoing factors may cause operational delays or restrictions, increased operating costs and additional regulatory burden. Additionally, litigation risks to oil and natural gas companies are increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. We are not currently a defendant in any of these lawsuits but could be named in actions making similar allegations.

Further, stockholders and bondholders currently invested in fossil fuel energy companies such as ours but concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made emission reduction commitments and have announced that they will be assessing financed emissions across their portfolios and are taking steps to quantify and reduce those emissions. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector, and more broadly, 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 natural gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. These and other developments in the financial sector could lead to some lenders and investors restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Such developments could result in downward pressure on the stock prices of oil and natural gas companies, including ours. This could also result in an increase in our expenses and a reduction of available capital funding for potential development projects, impacting our future financial results.

Additionally, increasing attention from consumers and other stakeholders on combating climate change, together with changes in consumer and industrial/commercial preferences and behavior and societal pressure on companies to address climate change may result in increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, geothermal, tidal and biofuels as well as electric vehicles) and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services. These developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, oil and natural gas products.

Lastly, most scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, rising sea levels and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for oil or natural gas products or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves, which may not be fully insured. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods, 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. Any of these effects could have an adverse effect on our assets and operations. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

Each of these developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, oil and natural gas products. Additionally, political, financial and litigation risks may result in us having to restrict, delay or cancel production activities, incur liability for infrastructure damages as a result of climatic changes, or impair the ability to continue to operate in an economic manner, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Increasing attention to ESG matters may impact our business.

Increasing scrutiny related to ESG matters, societal expectations for companies to address climate change and sustainability concerns, and investor, societal, and other stakeholder expectations regarding ESG and sustainability practices and related disclosures may result in increased costs, reduced demand for the oil and natural gas we produce, reduced profits, increased risks of governmental investigations and private party litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change, for example, may result in demand shifts for the hydrocarbon products we produce as well as additional governmental investigations and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the assented damage, or to other mitigating factors.

If we do not adapt to or comply with investor or other stakeholder expectations and standards on ESG matters as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to growing concern for ESG and sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition and/or stock price could be materially and adversely affected.

Further, our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. We may face pressure from stakeholders, including activist investors, many of whom are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability while at the same time remaining a successfully operating public company. Responses to such pressure could adversely impact our business by distracting management and other personnel from their primary responsibilities, require us to incur increased costs, and/or result in reputational harm. Moreover, 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.

Organizations that provide information to investors on corporate governance, climate change, health and safety and other ESG related factors have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with fossil energy-related assets could lead to increased negative investor sentiment toward us or our customers and to the diversion of investment to other industries, which could have a negative impact on our unit price and/or our access to and costs of capital.

In addition, our continuing efforts to research, establish, accomplish and accurately report on the implementation of our ESG strategy, including any specific ESG 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 ESG matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. In addition, our current ESG governance structure may not allow us to adequately identify or manage ESG-related risks and opportunities, which may include failing to achieve ESG-related strategies and goals.

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

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

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

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

Our articles of incorporation and bylaws, as well as Texas law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Certain provisions of our articles of incorporation and bylaws, as well as the Texas Business Organizations Code, could make it more difficult for a third-party to acquire control of us, even if the change of control would be beneficial to our stockholders. Among other things, our articles of incorporation and bylaws:

- provide advance notice procedures with regard to stockholder nominations of candidates for election as directors or other stockholder proposals to be brought before meetings of our stockholders, which may preclude our stockholders from bringing certain matters before our stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize issuance of preferred stock in one or more series, which makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us and which may have the effect of deterring hostile takeovers or delaying changes in control or management of us;

- provide that the authorized number of directors may be changed only by resolution of our board of directors;

- provide that, subject to the rights of holders of any series of preferred stock to elect directors or fill vacancies in respect of such directors as specified in the related preferred stock designation, all vacancies, including newly created directorships be filled by the affirmative vote of holders of a majority of directors then in office, even if less than a quorum, or by the sole remaining director, and will not be filled by our stockholders;

- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;

- provide that, subject to the rights of the holders of shares of any series of preferred stock, if any, to remove directors elected by such series of preferred stock pursuant to our articles of incorporation (including any preferred stock designation thereunder), directors may be removed from office at any time, only for cause and by the holders of 60% of the voting power of all outstanding voting shares entitled to vote generally in the election of directors;

- provide that special meetings of our stockholders may be called by the Chairman of our board of directors, our President, by our Secretary upon the written request of a majority of the total number of directors of our board of directors, or at least 25% of the voting power of all outstanding shares entitled to vote generally at the special meeting; and

- provide that the provisions of our articles of incorporation can only be amended or repealed by the affirmative vote of the holders of at least a majority in voting power of the outstanding shares of our common stock entitled to vote thereon, voting together as a single class.

Further, we are incorporated in Texas. The Texas Business Organizations Code contains certain provisions that could make an acquisition by a third party more difficult.

While we paid quarterly dividends during 2024, there can be no assurance that we will pay dividends in the future.

After reinstating our dividend policy in November 2023, we have paid quarterly dividends of $0.01 per share of common stock. We cannot provide assurance that we will, at any time in the future, again generate sufficient surplus cash that would be available for distribution to the holders of our common stock as a dividend or that our Board of directors would determine to use any of our net profits to pay a dividend.

Future dividends may be affected by, among other factors:

- the availability of surplus or net profits, which in turn depend on the performance of our business;
- our debt service requirements and other liabilities;
- restrictions contained in our debt agreements;
- our future capital requirements, including to fund our operating expenses and other working capital needs; and
- the prices that we receive for our oil, NGL and natural gas production.

A decision not to pay dividends or a reduction in our dividend payments in the future could have a negative effect on our stock price.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 1C. CYBERSECURITY

We maintain a cyber risk management program designed to identify, assess, manage, mitigate, and respond to cybersecurity threats. This program is integrated within our IT and risk management systems and addresses both the corporate and the operational IT environment.

The underlying controls of the cyber risk management program are based on recognized best practices and standards for cybersecurity and IT, including the National Institute of Standards and Technology (the "NIST"), the Control Objectives for Information Technologies ("COBIT") framework and the International Organization Standardization 27001, *Information Security Management System* requirements. We have an annual assessment, performed by our internal audit department, of our cyber risk management program against the NIST and COBIT frameworks.

Our information security practices include development, implementation, and improvement of policies and procedures to safeguard information and ensure availability of critical data and systems. We have adopted a Cybersecurity Incident Response Plan that applies if a security event occurs. Our Incident Response Plan provides a common framework for responding to security incidents. This framework establishes procedures for identifying, validating, categorizing, documenting, and responding to security events that are identified by or reported to the Chief Information Officer ("CIO"). Our Incident Response Plan applies to our personnel including contractors and partners that perform functions or services that require securing our information assets, and to all devices and networks that we own. The Incident Response Plan details the coordinated, multi-functional approach for investigating, containing, and mitigating incidents. Under our Incident Response Plan, cybersecurity incidents are escalated based on a defined incident categorization to the CIO and the General Counsel. Regular updates are provided by the Cybersecurity team to the CIO, who will maintain communication and information flow to senior leadership including the General Counsel, Chief Financial Officer, and other cybersecurity program stakeholders as well as the Audit Committee and/or the Board of Directors as appropriate. Generally, our incident response process follows the National Institute of Standards and Technology (NIST) framework and focuses on preparation; detection and analysis; containment, eradication, recovery and post-incident remediation.

Our CIO leads the information security organization which oversees the identification and management of information security risks. Our CIO has extensive information security and risk management experience in Information and Operational technology and holds the following information security certifications:

- Certified Information Systems Security Professional (CISSP);
- Certified Information Systems Auditor (CISA); and
- Certified Risk and Information Systems Control (CRISC).

Our CIO is a member of InfraGard, ISC2 and ISACA and serves as Adjunct Professor of Cyber Security at Lone Star College and San Jacinto College.

We conduct mandatory security training during new employee onboarding, as well as require our employees to complete annual security risk training and, when necessary, perform additional updated training. We also engage certain third-parties in assessing, identifying and managing cyber-security risks. These third parties perform a number of services, including managed detection and response services for information technology endpoints, anti-virus monitoring, penetration testing, and other miscellaneous cyber security programs and services. We maintain specific policies and practices governing our third-party security risks, including our third-party assessment process. Under our third-party assessment process, we gather information from certain third parties who contract with us and share or receive data, or have access to or integrate with our systems, in order to help us assess potential risks associated with their security controls. We require each third-party service provider to certify that it has the ability to implement and maintain appropriate security measures, consistent with all applicable laws, to implement and maintain reasonable security measures in connection with their work with us, and to promptly report any suspected breach of its security measures that may affect us.

The Audit Committee of our board of directors oversees our cybersecurity policies, procedures, risk exposures and the steps taken by management to monitor and mitigate cybersecurity risks. Our executive management, including our Vice President and Chief Information Officer, periodically updates and reports to the Audit Committee and the board of directors regarding cybersecurity risk exposure and our cybersecurity risk management strategy (at a minimum, once per quarter). Additionally, all members of the board of directors attend quarterly training sessions through internal and external IT specialists, which include review of IT whitepapers, presentations, and other learning materials. Each of the members of the board of directors has also completed certificated training concerning IT security, IT fraud, and other common enterprise-level IT threats.

We face risks from cybersecurity threats that could have a material adverse effect on our business, financial condition, results of operations, cash flows or reputation. To our knowledge, such risks have not materially affected our operations nor have we experienced any cybersecurity incidences which have impacted our operations. In the past three years, we have not experienced a material information security breach. We will continue to face cybersecurity threats whether directly or through our supply chain or other channels in the normal course of business. See *Risk Factors* in Part I, Item 1A in this Form 10-K for additional information.

ITEM 2. PROPERTIES

We lease our corporate headquarters in Houston, Texas. We own and lease our operating and administrative facilities in Alabama and Louisiana, respectively. We believe our properties and facilities are suitable and adequate for their present and intended purposes and are operating at a level consistent with the requirements of the industry in which we operate.

Proved Reserves

Our reserve information is derived from our reserve report prepared by Netherland, Sewell & Associates, Inc ("NSAI"), our independent reserve engineering firm. Our estimates of proved reserves are based on the quantities of oil, NGLs 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 estimate.

In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating of and Auditing of Oil & Gas Reserves information promulgated by the Society of Petroleum Engineers (SPE Standards). NSAI used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy and reservoir modeling that are considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations.

The data in the table below represents estimates only. Oil, NGLs and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil, NGLs 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, NGLs and natural gas that are ultimately recovered.

The following table presents our estimated net proved reserves at December 31, 2024:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	MMBoe	PV-10 (in millions)
Proved developed producing	19.5	8.2	229.4	66.0	$ 549.8
Proved developed non-producing	17.5	4.0	106.6	39.3	520.7
Total proved developed	37.0	12.2	336.0	105.3	1,070.5
Proved undeveloped	14.6	0.8	38.4	21.7	159.0
Total proved	51.6	13.0	374.4	127.0	$ 1,229.5

In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2024 were calculated using the WTI oil average spot price of $76.32 per barrel and the Henry Hub natural gas average spot price of $2.13 per MMBtu as the referenced price and, after adjusting for quality, transportation, fees, energy content and regional price differences, the adjusted average product prices were $74.69 per barrel for oil, $22.98 per barrel for NGLs and $2.58 per Mcf for natural gas. In determining the estimated price for NGLs, a ratio was computed for each field of the NGL realized price compared to the WTI oil spot price. This ratio was then applied to the oil price using SEC guidance. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalation.

Reconciliation of Standardized Measure to PV-10

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure of discounted future net cash flows is the after-tax 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 and debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Future income tax expenses are calculated by applying the year-end statutory tax rates to the pre-tax net cash flows. The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor, which is required by Financial Accounting Standards Board pronouncements, 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.

At December 31, 2024, our proved reserves had a standardized measure of discounted future net cash flows of $740.1 million and a present value of future net pre-tax cash flows attributable to estimated net proved reserves, discounted at 10% per annum (“PV-10”) of $1,229.5 million. PV–10 is a computation of the standardized measure of discounted future net cash flows on a pre–tax basis and is computed on the same basis as standardized measure but does not include a provision for federal income taxes, Texas gross margin tax or other state taxes.

Neither PV-10 nor PV-10 before ARO are financial measures defined under accounting principles generally accepted in the United States of America ("GAAP"); therefore, the following table reconciles these amounts to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the non-GAAP financial measures of PV-10 and PV-10 before ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 before ARO are used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. We believe the use of pre-tax measures is valuable because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid. Management believes that the presentation of PV-10 and PV-10 before ARO provide useful information to investors because they are widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 and PV-10 before ARO are not measures of financial or operating performance under GAAP, nor are they intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 before ARO should not be considered in isolation or as substitutes for the standardized measure of discounted future net cash flows as defined under GAAP. Investors should not assume that PV-10, or PV-10 before ARO, of our proved oil and natural gas reserves shown above represent a current market value of our estimated oil and natural gas reserves.

The table below provides a reconciliation of PV-10 and PV-10 before ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves (in millions):

	December 31,		
	2024	**2023**	**2022**
PV-10	$ 1,229.5	$ 1,080.9	$ 3,128.6
Future income taxes, discounted at 10%	(154.8)	(151.0)	(594.1)
PV-10 before ARO	1,074.7	929.9	2,534.5
Present value of estimated ARO, discounted at 10%	(334.6)	(246.7)	(271.5)
Standardized measure	$ 740.1	$ 683.2	$ 2,263.0

Changes in Proved Reserves

The following table discloses our estimated changes in proved reserves during 2024:

	MMBoe
Proved reserves at December 31, 2023	123.0
Reserves additions (reductions):	
Revisions [1]	(5.5)
Purchases of minerals in place	21.7
Production	(12.2)
Net reserve additions (reductions)	4.0
Total proved reserves at December 31, 2024	127.0

(1) Net revisions are primarily attributable to lower commodity prices.

See *Proved Undeveloped Reserves* below for a table reconciling the change in PUDs during 2024. See *Financial Statements and Supplementary Data – Note 18 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

Proved Undeveloped Reserves

PUDs are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. All proved undeveloped locations conform to the SEC rules defining proved undeveloped locations. We do not have any reserves that would be classified as synthetic oil or synthetic natural gas.

The following table presents changes in our PUDs (in MMBoe):

	December 31,		
	2024	2023	2022
PUDs, beginning of year	19.7	20.5	20.6
Revisions of previous estimates	0.8	(1.3)	(0.1)
Purchase of minerals in place	1.2	0.5	—
PUDs, end of year	21.7	19.7	20.5

The revisions of previous estimates were due to changes in SEC pricing.

We annually review all PUDs to ensure an appropriate plan for development exists. The following table presents our estimates as to the timing of converting our PUDs to proved developed reserves:

Year Scheduled for Development	Number of PUD Locations	Percentage of PUD Reserves Scheduled to be Developed
2025	—	— %
2026	12	79 %
2027	2	18 %
2028	—	— %
2029+	1	3 %
Total	15	100 %

As of December 31, 2024, we believe that we will be able to develop all but 5.9 MMBoe (approximately 27%) of the total 21.7 MMBoe classified as PUDs within five years from the date such PUDs were initially recorded. The primary exceptions are at the Mississippi Canyon 243 field ("Matterhorn"), Ship Shoal 349 field ("Mahogany") and

Viosca Knoll 823 field ("Virgo") where future development drilling has been planned as sidetracks of existing wellbores due to conductor slot limitations and rig availability. Three sidetrack PUD locations, one each at Matterhorn, Mahogany and Virgo, will be delayed until an existing well is depleted and available to sidetrack. We also plan to recomplete and convert an existing producer at Matterhorn to water injection for improved recovery following depletion of the existing well. Based on the latest reserve report, these PUD locations are expected to be developed in 2026 and 2036. The other exception is at the Garden Banks 783 field ("Magnolia") where significant spending has already begun on rig and platform modifications for development drilling, but the timeline has been extended to 2026 before we will be able to mobilize the rig. Future development costs associated with our PUDs at December 31, 2024 were estimated at $659.8 million.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our policies and procedures regarding internal controls over the recording of our reserves is structured to objectively and accurately estimate our reserves quantities and present values in compliance with both accounting principles generally accepted in the United States and the SEC's regulations.

Our estimated proved reserve information as of December 31, 2024 included in this Form 10-K was prepared by our independent petroleum consultants, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The NSAI report is based on its independent evaluation of engineering and geophysical data, product pricing, operating expenses, and the reasonableness of future capital requirements and development timing estimates provided by us. The scope and results of their procedures are summarized in a letter included as an exhibit to this Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has been practicing consulting petroleum engineering at NSAI since 2015 and has over six years of prior industry experience. NSAI has informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. Additionally, our senior management reviews any significant changes to our proved reserves on a quarterly basis. Our Director of Reservoir Engineering has over 35 years of oil and gas industry experience and has managed the preparation of public company reserve estimates the last 21 years. He joined the Company in 2016 after spending the preceding 12 years as Director of Corporate Engineering for Freeport-McMoRan Oil & Gas. He has also served in various engineering and strategic planning roles with both Kerr-McGee and with Conoco, Inc. He earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1989 and a master's degree in Business Administration from the University of Houston in 1999.

Reserve Technologies

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our independent petroleum consultant employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;

- the accuracy of various mandated economic assumptions such as the future prices of oil, NGLs and natural gas; and
- the judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered.

Reporting of Natural Gas and Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. We report all natural gas production information net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs.

Developed and Undeveloped Acreage

The following table summarizes our developed and undeveloped acreage at December 31, 2024:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	469,158	413,460	23,813	23,813	492,971	437,273
Deepwater	141,929	56,540	5,760	5,760	147,689	62,300
Alabama State Waters	5,553	2,716	—	—	5,553	2,716
Total	616,640	472,716	29,573	29,573	646,213	502,289

Our net acreage increased 62,258 net acres (14%) from December 31, 2023 due to leases acquired in the January 2024 acquisition offset by lease expirations.

Approximately 94.1% of our net acreage is held by production. We have the right to propose future exploration and development projects on the majority of our acreage. The following table presents the timing of expiration of our undeveloped leasehold acreage:

	Undeveloped Acreage	
	Net	Percent of Total
2025	8,813	30%
2026	—	0%
2027	10,760	36%
2028	10,000	34%
Thereafter	—	0%
Total	29,573	100%

In making decisions regarding drilling and operations activity for 2025 and beyond, we give consideration to undeveloped leasehold interests that may expire in the near term in order that we might retain the opportunity to extend such acreage.

Drilling Activity

We did not complete any wells during 2024 and 2023. During 2022, we completed two gross (0.6 net) exploratory wells, of which one gross (0.3 net) well is currently producing.

Productive Wells

Productive wells consist of producing wells and wells capable of production. Gross wells are the total number of productive wells in which we have a working interest, regardless of our percentage interest. A net well is not a physical well but is a concept that reflects actual working interest we hold in a given well. Our wells may produce both oil and natural gas. We classify a well as an oil well if the net equivalent production of oil was greater than natural gas for the well.

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2024:

	Oil Wells (1)		Gas Wells (2)		Total Wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operated	163.0	154.4	97.0	87.8	260.0	242.2
Non-operated	34.0	5.8	8.0	2.7	42.0	8.5
Total	197.0	160.2	105.0	90.5	302.0	250.7

(1) Includes 17 gross (16.0 net) oil wells with multiple completions.

(2) Includes 3 gross (2.6 net) natural gas wells with multiple completions.

Production Data

See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations* under Part II, Item 7 in this Form 10-K for additional information.

ITEM 3. LEGAL PROCEEDINGS

See *Financial Statements and Supplementary Data – Note 6 – Commitments and Contingencies* under Part II, Item 8 in this Form 10-K for information on various legal proceedings to which we are party or our properties are subject.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

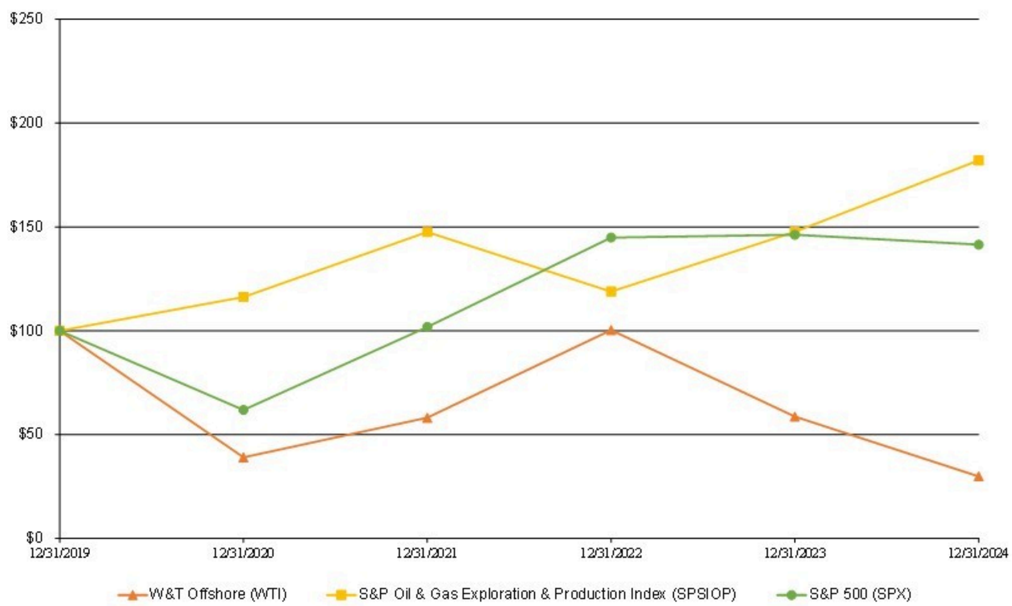
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of March 1, 2025, there were 127 registered holders of our common stock.

Dividends

On March 3, 2025, our board of directors declared a quarterly cash dividend of $0.01 per share of common stock, or approximately $1.5 million, to be paid on March 24, 2025 to shareholders of record at the close of business on March 17, 2025. The decision to pay additional dividends on our common stock is at the discretion of our board of directors and is subject to periodic review of our performance, which includes the current economic environment and applicable debt agreement restrictions.

Stock Performance Graph

The performance graph below shows the cumulative total shareholder return on our common stock compared with the S&P Oil and Gas Exploration and S&P 500 indices over the five-year period beginning on December 31, 2019. The results are based on an investment of $100 in our common stock, the S&P Oil and Gas Exploration and the S&P 500. The graph assumes reinvestment of dividends. The information contained in the graph below is furnished and not filed and is not incorporated by reference into any document that incorporates this Form 10-K by reference.



Equity Compensation Plan Information

For equity compensation plan information, refer to *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* under Part III, Item 12 in this Annual Report on Form 10-K.

Issuer Purchases of Equity Securities

None.

Unregistered Sales of Equity Securities

None.

ITEM 6. [RESERVED]

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

The following discussion and analysis of our financial condition and results of operations is based on, and should be read in conjunction with Part I, Item 1. *Business*, Item 1A. *Risk Factors*, Item 2. *Properties* and Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and with Part 1I, Item 8. *Financial Statements and Supplementary Data* and other financial information appearing elsewhere in this 2024 Form 10-K. The following discussion and analysis includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those anticipated in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in Part I, Item 1A. *Risk Factors*.

This section primarily discusses 2024 and 2023 items and comparisons between 2024 and 2023. Discussions of 2023 items and comparisons between 2023 and 2022 that are not included in this Form 10-K are incorporated by reference to Part II, 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.

Business Overview

We are an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties in the Gulf of America. As of December 31, 2024, we held working interests in 52 offshore producing fields in federal and state waters (which include 45 fields in federal waters and seven in state waters). We currently have under lease approximately 646,200 gross acres (502,300 net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 5,500 gross acres in Alabama state waters, 493,000 gross acres on the conventional shelf and approximately 147,700 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. Our interests in fields, leases, structures and equipment are primarily owned by our wholly-owned subsidiaries and through our proportionately consolidated interest in Monza Energy LLC.

In managing our business, we are focused on optimizing production and making profitable investments, pursuing high rate of return projects and developing oil and natural gas resources in a manner that allows us to grow our production, reserves and cash flow in a capital efficient manner, organically enhancing the value of our assets.

Recent Developments

Business and Operational Updates

On January 16, 2024, we closed on our acquisition of rights, titles and interest in and to certain leases, wells and personal property in the central shelf region of the Gulf of America, among other assets, for $77.3 million (including closing fees and other transaction costs). The acquisition was funded using cash on hand. We also assumed the related

AROs associated with these assets. This transaction is described in more detail under *Financial Statements and Supplementary Data – Note 2 – Acquisitions*, under Part II, Item 8 of this Annual Report.

In December 2024, we entered into a purchase and sale agreement to sell a non-core interest in the Garden Banks Blocks 385 and 386. The effective date of the sale was December 1, 2024, and the transaction closed on January 8, 2025 for approximately $11.9 million following customary purchase price adjustments.

Effective December 20, 2024, we entered into a resolution with the third-party pipeline operator at our West Delta 73 field. As a result of this resolution, we expect to restart production from the field in the second quarter of 2025. We originally acquired the West Delta 73 field in our January 2024 acquisition.

In June 2024, we received notice from BSEE that we would be required to cease production at our Main Pass 108 and 98 fields as the result of a shut-in of midstream infrastructure not owned by us. On December 11, 2024, we entered into a purchase agreement and other arrangements with the trustee of the bankruptcy estate of Energy XXI GOM, LLC and Cox Operating L.L.C. (the “Cox Trustee”) to acquire the necessary midstream infrastructure, which is expected to allow us to return the Main Pass 108 and 98 fields to production in the second quarter of 2025. Following developments in connection with the acquisition of the midstream infrastructure, on February 25, 2025, we mutually terminated the purchase agreement with the Cox Trustee and entered into a new purchase agreement with the Cox Trustee including the midstream infrastructure and additional properties. The closing of the acquisitions contemplated by the purchase agreement and subsequent return to production are subject to our obtaining approval from the Bankruptcy Court for the Southern District of Texas, necessary governmental approvals and permits in connection with the acquisitions, in addition to customary closing conditions.

In January 2025, we received $58.5 million related to the settlement of claims related to the Mobile Bay plant turnaround in February 2023. During the turnaround, the MB 78-1 well was shut-in and did not return to production following completion of the planned maintenance. We filed a claim under our Energy Package Policy and in December 2024, we and the underwriters of the Energy Package Policy agreed to a settlement of claims.

Issuance of 10.75% Notes and Related Transactions

On January 28, 2025, we issued $350.0 million of 10.75% Notes. The 10.75% Notes were issued at par and mature on February 1, 2029. The net proceeds from the issuance of the 10.75% Notes along with cash on hand were used to (i) purchase for cash pursuant to a tender offer (the “Tender Offer”), such of our 11.75% Senior Second Lien Notes due 2026 (the “11.75% Notes”) that were validly tendered (and not validly withdrawn) pursuant to the Tender Offer, (ii) on or after August 1, 2025, redeem in full any remaining 11.75% Notes not validly tendered and accepted for purchase in the Tender Offer and, pending such redemptions, satisfy and discharge the indenture governing the 11.75% Notes; (iii) repay outstanding amounts under the credit agreement of certain of our indirect, wholly-owned subsidiaries (the “Term Loan”), and (iv) pay any premiums, fees and expenses relating to these transactions.

Termination of Credit Agreement and Entry into New Credit Agreement

On January 28, 2025, in conjunction with the issuance of the 10.75% Notes, we terminated our Sixth Amended and Restated Credit Agreement (the “Credit Agreement”) and entered into the New Credit Agreement which provides us a revolving credit and letter of credit facility with initial bank lending commitments of $50.0 million with a letter of credit sublimit of $10.0 million. The New Credit Agreement matures on July 28, 2028.

See *Financial Statements and Supplementary Data – Note 19 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

Business Outlook

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Changes in the prices that we receive for our production impact all aspects of our business; most notably our cash flows from operations, revenues, capital allocation and budgeting decisions and our reserves volumes. Prices of oil, NGLs and natural gas have historically been volatile and can fluctuate significantly over short periods of time for many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, domestic production activities and political issues, and international geopolitical and economic events.

The EIA published its latest Short-Term Energy Outlook in January 2025. The EIA expects downward oil price pressures over much of the next two years as they expect that global oil production will grow more than global oil demand. The EIA forecasts that the spot price for WTI oil will average $70.33 per barrel in 2025, 8% less than 2024, and then continue to fall another 11% to $62.50 per barrel in 2026. The unwinding of OPEC+ production cuts and strong growth in oil production outside of OPEC+ results in global oil production growing in the EIA forecast. Although the EIA is forecasting OPEC+ will increase production, they expect the group will produce less oil than stated in its most recent production target in an effort to avoid significant inventory builds.

The EIA expects the spot prices for Henry Hub natural gas to average $3.14 per MMBtu in 2025 and $3.97 per MMBtu in 2026, up from a historically low average of $2.19 per MMBtu in 2024. The EIA expects wholesale natural gas prices to increase because growth in demand, led by liquified natural gas exports, will outpace production growth and keep inventories in the next two years at or below their previous five-year averages.

Our average realized sales price for oil and natural gas differs from the WTI average price and the NYMEX Henry Hub average price, respectively, primarily due to premiums or discounts, quality adjustments, location adjustments and volume weighting (collectively referred to as differentials). Oil price differentials primarily represent the transportation costs in moving produced oil at the wellhead to a refinery and are based on the availability of pipeline, rail and other transportation. Natural gas price differentials are strongly impacted by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. Prices and differentials for NGLs are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products which are used as feedstock.

In addition to the impact of volatile commodity prices on our operations, continuing inflation could also impact our sales margins and profitability. The United States has experienced a rise in inflation since October 2021. Inflation peaked during mid-2022 at 9.1% but the rate of inflation has been gradually declining since the second half of 2022 according to the Consumer Price Index (the "CPI"). The annual inflation rate for December 2024 was 2.9%, a decrease from the 3.4% rate for December 2023. However, the annual inflation rate of January 2025 was 3.0%, an increase from the 2.9% rate for December 2024. Beginning in September 2024, the Federal Reserve made three cuts to the target federal funds rate, bringing the target federal funds range down to 4.25% to 4.50%, easing monetary policy for the first time in four years due to progress in inflation moving sustainably toward 2%. The Summary of Economic Projections published by the Federal Reserve in December 2024 points to another 50 basis points of cuts in 2025. However, if inflation were to continue to rise again, it is possible the Federal Reserve would continue to take action they deem necessary to bring inflation down and to ensure price stability, including targeted federal funds rate increases, which could have the effects of raising the cost of capital and depressing economic growth, either or both of which could negatively impact our business.

Key Challenges and Uncertainties

In addition to general market conditions and competition in the oil and natural gas industry, we believe the following represent the key challenges and uncertainties we will face in the future.

Commodity Prices

A prolonged period of weak commodity prices may create uncertainties in our financial condition and results of operations. Such uncertainties may include:

- ceiling test write-downs of the carrying value of our oil and natural gas properties;
- reductions in our proved reserves and the estimated value thereof;
- additional supplemental bonding and potential collateral requirements; and
- our ability to fund capital expenditures needed to replace produced reserves, which must be replaced on a long-term basis to provide cash to fund liquidity needs.

Deferred Production

Since our operations are in the Gulf of America, we are particularly vulnerable to the effects of hurricanes on production and operations. Significant hurricane impacts include reductions and/or deferrals of future oil and natural gas production and revenues, increased lease operating expenses for evacuations and repairs and possible acceleration of plugging and abandonment costs.

Our production was impacted due to precautionary shut-ins of facilities and evacuations associated with Hurricanes Francine, Helene and Rafael. For 2024, we estimate deferred production related to Hurricane Francine was approximately 132.8 MBoe and affected 35 fields, deferred production related to Hurricane Helene was approximately 17.2 MBoe and affected five fields and deferred production related to Hurricane Rafael was approximately 3.4 MBoe and affected three fields.

Production downtime following these hurricanes was extended as a result of damage and power loss at third party downstream facilities, including oil terminals, natural gas processing plants and refineries, causing them to remain offline for several weeks. While our assets and infrastructure did not suffer significant damage during the storm, we incurred $1.1 million of unplanned costs for minor repairs and restoring production, as well as evacuating employees and contractors, as a result of the hurricane. These amounts are reflected in lease operating expense.

In addition, our oil, NGLs and natural gas production can also be significantly affected by both planned and unplanned production downtime caused by events such as planned repairs and upgrades, third-party downtime associated with non-operated properties and the transportation, gathering or processing of production and weather events. For 2024, we estimate deferred production was approximately 2.6 MMBoe, excluding the deferred production from the hurricanes.

BOEM Matters

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to satisfy lease obligations, including decommissioning activities on the OCS. In April 2024, BOEM released a final rule that changes the way BOEM evaluates the financial health of companies and offshore assets in setting financial assurance requirements. Under the new rule, BOEM streamlined the criteria used to evaluate the financial health of an energy company down to two factors: (i) the company's credit rating, and (ii) the ratio of the value of the company's proved reserves to decommissioning liability associated with those reserves. The new rule also codifies the usage of BSEE decommissioning estimates to evaluate supplemental financial assurance requirements and allows third party guarantors (upon agreement with BOEM) to provide limited guarantees to specific amounts or specific leases instead of the blanket guarantees that have been used in the past. Finally, the new rule also requires a base financial assurance requirement of $500,000 for federal RUEs to match the requirement for state RUEs. To provide the industry with flexibility to meet the new financial assurance requirements, BOEM will allow current lessees and grant holders to request phased-in payments over a three-year period. BOEM estimates that the industry will be required to provide $6.9 billion in new financial assurances under the new rule, which took effect on June 29, 2024. Following the announcement of the new rule, a series of lawsuits from both states and industry groups have been filed against BOEM to block the implementation of the new rule. We are actively monitoring ongoing litigation with respect to the new rule. However, President Trump may seek to suspend, revise or rescind this final rule pursuant to Interior Secretary Burgum's Secretarial Order 3418 dated February 2, 2025. The substance and timing of such legal and regulatory actions cannot be predicted at this time. The future cost of compliance with respect to supplemental financial assurances, including the obligations imposed on us, whether as current or predecessor lessee or grant holder in respect of BOEM's final rule or any new, more stringent, rules related to supplemental financial assurances could materially and adversely affect our financial condition, cash flows, liquidity and results of operations. Additionally, regardless of the final rule, BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities. For more information on the BOEM and financial assurance obligations to that agency, see *Business – Environmental, Health and Safety Matters and Government Regulations – Other Regulation of the Oil and Natural Gas Industry* under Part I, Item 1 of this Form 10-K.

Bonding

In prior years, some of the sureties, which provided us surety bonds that we use for supplemental financial assurance purposes, requested and received collateral from us. Pursuant to the terms of our agreement with various sureties under out existing bonding arrangements, we may be required to post collateral. These sureties may request additional collateral from us in the future, which could be significant and could materially impact our liquidity.

To the extent we are unable to provide collateral or provide an adequate alternative, including financing, we may be forced to reduce our capital expenditures in the current year or future years, may be unable to execute our ARO plan or may be unable to comply with our existing debt instruments.

To the extent that the Sureties succeed in forcing us to fulfill the Demanded Collateral, or in the event that other surety entities attempt to do the same, the fulfilment of such demands could be significant and our liquidity position could be negatively impacted, and we may be required to seek alternative financing.

For more information on risks associated with our bonding, please see *Risk Factors* under Part I, Item 1A of this Form 10-K.

RESULTS OF OPERATIONS

Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs. Our oil, NGL and natural gas revenues do not include the effects of derivatives, which are reported in *Derivative (gain) loss, net* in our Consolidated Statements of Operations.

The following table presents information regarding our revenues, production volumes and average realized sales prices (which exclude the effect of hedging unless otherwise stated) for 2024 and 2023 (in thousands, except average realized sales prices data):

	Year Ended December 31, 2024	Year Ended December 31, 2023	Change
Revenues:			
Oil	$ 395,620	$ 381,389	$ 14,231
NGLs	27,978	32,446	(4,468)
Natural gas	90,877	110,158	(19,281)
Other	10,786	8,663	2,123
Total revenues	$ 525,261	$ 532,656	$ (7,395)
Production Volumes:			
Oil (MBbls)	5,255	5,050	205
NGLs (MBbls)	1,212	1,415	(203)
Natural gas (MMcf)	34,296	37,591	(3,295)
Total oil equivalent (MBoe)	12,183	12,730	(547)
Average daily equivalent sales (Boe/day)	33,287	34,877	(1,590)
Average realized sales prices:			
Oil ($/Bbl)	$ 75.28	$ 75.52	$ (0.24)
NGLs ($/Bbl)	23.08	22.93	0.15
Natural gas ($/Mcf)	2.65	2.93	(0.28)
Oil equivalent ($/Boe)	42.23	41.16	1.07
Oil equivalent ($/Boe), including realized commodity derivatives	42.47	40.84	1.63

Changes in average sales prices and production volumes caused the following changes to our oil, NGL and natural gas revenues between 2024 and 2023 (in thousands):

	Price	Volume	Total
Oil	$ (1,208)	$ 15,439	$ 14,231
NGLs	172	(4,640)	(4,468)
Natural gas	(9,626)	(9,655)	(19,281)
	$ (10,662)	$ 1,144	$ (9,518)

Production volumes decreased by 547 MBoe to 12,183 MBoe during 2024 compared to the same period in 2023, primarily due to deferred production of approximately 0.8 MMBoe at our Mobile Bay Properties, approximately 0.3 MMBoe from the shut-on of the MP 98 and 108 fields and approximately 0.2 MMBoe from the effects of Hurricanes Francine, Helene and Rafael. These decreases were partially offset by approximately 1.9 MMBoe of production from wells acquired in both the January 2024 and the September 2023 acquisitions.

Operating Expenses

The following table presents information regarding costs and expenses and selected average costs and expenses per Boe sold for the periods presented and corresponding changes (in thousands):

	Year Ended December 31,		
	2024	2023	Change
Operating expenses:			
Lease operating expenses	$ 281,488	$ 257,676	$ 23,812
Gathering, transportation and production taxes	28,177	26,250	1,927
Depreciation, depletion and amortization	143,025	114,677	28,348
Asset retirement obligations accretion expense	32,374	29,018	3,356
General and administrative expenses	82,391	75,541	6,850
Total operating expenses	$ 567,455	$ 503,162	$ 64,293
Average per Boe ($/Boe):			
Lease operating expenses	$ 23.10	$ 20.24	$ 2.86
Gathering, transportation and production taxes	2.31	2.06	0.25
Depreciation, depletion and amortization	11.74	9.01	2.73
Asset retirement obligations accretion expense	2.66	2.28	0.38
General and administrative expenses	6.76	5.93	0.83
Total operating expenses	$ 46.57	$ 39.52	$ 7.05

Lease operating expenses

Lease operating expenses include the expense of operating and maintaining our wells, platforms and other infrastructure primarily in the Gulf of America. These operating costs are comprised of several components including direct or base lease operating expenses, insurance premiums, workover costs and facility maintenance expenses. Our lease operating costs, which depend in part on the type of commodity produced, the level of workover activity and the geographical location of the properties, increased $23.8 million to $281.5 million in 2024 compared to $257.7 million in 2023. On a per Boe basis, lease operating expenses increased to $23.10 per Boe during 2024 compared to $20.24 per Boe during 2023. On a component basis, base lease operating expenses increased $30.2 million, facility maintenance expenses increased $7.9 million and hurricane repairs increased $1.0 million, These increases were partially offset by a decrease of $15.3 million in workover expenses.

Expenses for direct labor, materials, supplies, repair, third-party costs and insurance comprise the most significant portion of our base lease operating expense. Base lease operating expenses increased primarily due to increases of $37.5 million of expenses at the fields acquired in January 2024 and September 2023 partially offset by $6.1 million of reduced expenses from the abandonment work to shutdown certain of our fields.

Workover and facilities maintenance expenses consist of costs associated with major remedial operations on completed wells to restore, maintain or improve the well's production. Since these remedial operations are not regularly scheduled, workover and maintenance expense are not necessarily comparable from period to period. The decrease in workover expenses and the increase in facilities maintenance expenses were due to the timing and mix of projects undertaken.

Hurricane expenses consist of costs for minor repairs and restoring production, as well as evacuating employees and contractors incurred as a result of Hurricanes Francine, Helene and Rafael.

Gathering, transportation and production taxes

Gathering and transportation consist of costs incurred in the post-production shipping of oil, NGLs, and natural gas to the point of sale. Production taxes consist of severance taxes levied by the Alabama Department of Revenue , the Louisiana Department of Revenue and the Texas Department of Revenue on production of oil and natural gas from land or water bottoms within the boundaries of each state. Gathering, transportation and production taxes increased to $28.2 million in 2024 compared to $26.3 million in 2023, primarily due to increase of $1.5 million in gathering and transportation fees and $0.4 million in production taxes. Gathering and transportation fees increased during the first half of 2024 compared with the first half of 2023 primarily related to higher production volumes in the first quarter of 2024 and higher processing fees for our Mobile Bay production that had to be re-routed to a different processing plant due to the shut-in of our primary Mobile Bay processing plant. These fees decreased in the second half of 2024 as our production volumes decreased compared with the same period in 2023. The increase in production taxes is primarily related to the start of payments to the state of Louisiana from our acquisition of oil and natural gas properties in September 2023.

Depreciation, depletion and amortization

Depreciation, depletion and amortization expense ("DD&A") is the expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas reserves. We use the full cost method of accounting for oil and natural gas activities. DD&A increased $28.3 million for 2024 compared to 2023 primarily due to increases of $33.3 million from an increase in the depletion rate per Mcfe and $1.3 million for depreciation of other property and the corporate airplane acquired in May 2023, partially offset by $6.3 million from the decrease in production for 2024 compared with 2023. The DD&A rate increased to $11.74 per Boe in 2024 from $9.01 per Boe in 2023. The DD&A rate per Boe increased primarily as a result of a higher depreciable base due to our January 2024 acquisition, increases in capital expenditures, future development costs and capitalized ARO and lower proved reserves.

Asset retirement obligations accretion expense

Accretion expense is the expensing of the changes in value of our ARO as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values. Accretion expense increased to $32.4 million in 2024 compared to $29.0 million in 2023 primarily due to our acquisition in January 2024 and revisions to the estimates used in calculating the liability.

General and administrative expenses

General and administrative ("G&A") expenses generally consist of costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production operations, bad debt expense, share-based compensation costs, audit and other fees for professional services and legal compliance. For 2024, G&A expenses were $82.4 million compared to $75.5 million in 2023. The increase is primarily due to increases of (i) $4.0 million in payroll costs consisting of $1.8 million related to merit and headcount increases and a $2.2 million employee retention credit recorded in 2023, (ii) $2.8 million in non-recurring legal fees and (iii) $1.9 million in medical claims cost, partially offset by a $2.1 million decrease in short-term incentive compensation costs.

Other Income and Expense

The following table presents the components of other income and expense for the periods presented and corresponding changes (in thousands):

	Year Ended December 31,		
	2024	2023	Change
Interest expense, net	$ 40,454	$ 44,689	$ (4,235)
Derivative gain, net	(3,589)	(54,759)	51,170
Other expense, net	18,071	5,621	12,450
Income tax (benefit) expense	(9,985)	18,345	(28,330)

Interest expense, net

Interest expense, net of interest income, decreased $4.2 million for 2024 compared with 2023 primarily due to decreases of $7.9 million from the redemption in February 2023 of our 9.75% Senior Second Lien Notes due 2023 and $1.9 million from the lower outstanding principal balance of the Term Loan, partially offset by $2.8 million incurred on the 11.75% Notes issued in late January 2023 and a $2.6 million decrease in interest income.

Derivative gain, net

Unrealized gains or losses on open derivative contracts relate to production for future periods; however, changes in the fair value of all of our open derivative contracts are recorded as a gain or loss on our Consolidated Statements of Operations at the end of each month. During 2024, the $3.6 million derivative gain consisted of $2.9 million of realized gains on settled contracts and $0.7 million of unrealized gain, net, from the increase in the fair value of the open contracts. During 2023, the $54.8 million derivative gain consisted of $4.1 million of realized losses on settled contracts and $58.9 million of unrealized gain, net, from the increase in the fair value of the open contracts.

As a result of the derivative contracts we have on our anticipated natural gas production volumes through April 2028, we expect these activities to continue to impact net income based on fluctuations in market prices for natural gas.

Other expense, net

During 2024, other expense, net, was $18.1 million, compared to $5.6 million for 2023. During 2024 and 2023, other expense primarily consisted of $20.9 million and $6.2 million, respectively, of additional expenses for net abandonment obligations pertaining to a number of legacy Gulf of America properties, partially offset by fees paid by producers to tie into our subsea equipment at one of our wells.

Income tax (benefit) expense

Our effective tax rates for 2024 and 2023 were 10.3% and 54.0%, respectively. These rates differed from the federal statutory rate of 21% primarily due to the impact of state income taxes, non-deductible compensation and adjustments to the valuation allowance on our deferred tax assets.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Overview

Our primary liquidity needs are to fund capital and operating expenditures and strategic acquisitions to allow us to replace our oil and natural gas reserves, repay and service outstanding borrowings, operate our properties and satisfy our ARO. We have funded such activities in the past with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank and other borrowings, and expect to continue to do so in the future.

We expect to support our business requirements primarily with cash on hand and cash generated from operations. As of December 31, 2024, we had $109.0 million of available cash on hand and $50.0 million available under our Credit Agreement, based on a borrowing base of $50.0 million. We also have up to approximately $83.0 million of availability through our “at-the-market” equity offering program, pursuant to which we may offer and sell shares of our common stock from time to time. Based on our current financial condition and current expectations of future market conditions, we believe our cash on hand, cash flows from operating activities and access to the equity markets from our “at-the-market” equity offering program will provide us with additional liquidity to continue our growth to take advantage of the current commodity environment and will allow us to meet our cash requirements for at least the next 12 months and beyond.

We continuously review our liquidity and capital resources. If market conditions were to change, for instance, due to uncertainty created by geopolitical events, a pandemic or a significant prolonged decline in oil and natural gas prices, and our revenue was reduced significantly or operating costs were to increase significantly, our cash flows and liquidity could be negatively impacted.

Cash Flow Information

The following table summarizes cash flows provided by (used in) by type of activity for the following periods (in thousands):

	Year Ended December 31,		
	2024	2023	Change
Operating activities	$ 59,539	$ 115,326	$ (55,787)
Investing activities	(118,177)	(81,608)	(36,569)
Financing activities	(8,562)	(321,737)	313,175

Operating activities – Net cash provided by operating activities for 2024 was $59.5 million, decreasing $55.8 million from 2023. This was primarily due to decreases of $37.6 million in net (loss) income adjusted for certain non-cash items and $18.2 million from changes in operating assets and liabilities. The decrease in net (loss) income adjusted for certain non-cash items was primarily related to a $7.4 million decrease in revenues and increases in cash operating expenses, partially offset by a $13.5 million increase in derivative cash receipts. The decrease in operating assets and liabilities is primarily related to lower accounts receivable balances due to decreased revenues partially offset by higher accounts payable and accrued liabilities balances in the current period.

Investing activities – Net cash used in investing activities for 2024 increased $36.6 million compared to 2023. This was primarily due to an increase of $53.3 million in acquisition of property interests, partially offset by a decrease of $4.5 million in investment in oil and natural gas properties and the purchase of the corporate aircraft during 2023.

Financing activities – Net cash used in financing activities during 2024 decreased by $313.2 million compared to 2023. This was primarily due to the redemption of the $552.5 million principal amount outstanding of the 9.75% Notes in February 2023 partially offset by the net cash proceeds of $275.0 million received from the issuance of the 11.75% Notes in January 2023.

Capital Expenditures

The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors including the prices of oil, NGLs and natural gas, acquisition opportunities, liquidity and financing options and the results of our exploration and development activities.

The following table presents our investments in oil and gas properties and equipment for exploration, development, acquisitions and other leasehold costs (in thousands):

	Year Ended December 31,	
	2024	2023
Exploration and development		
Conventional shelf [1]	$ 17,755	$ 14,464
Deepwater	7,650	25,551
Acquisitions of interests	80,635	27,384
Seismic and other	8,150	1,263
Investments in oil and gas property/equipment – accrual basis	$ 114,190	$ 68,662

(1) Includes exploration and development capital expenditures in Alabama state waters.

Our preliminary capital expenditure budget for 2025 has been established in the range of $34.0 million to $42.0 million, which excludes acquisitions. In our view of the outlook for 2025, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2025 and beyond while providing liquidity to make strategic acquisitions. At current pricing levels, we expect our cash flows to cover our liquidity requirements, and we expect additional financing sources to be available if needed. If our liquidity becomes stressed from significant or prolonged reductions in realized prices, we have flexibility in our capital expenditure budget to reduce investments. We strive to maintain flexibility in our capital expenditure projects and if commodity prices improve, we may increase our investments.

Acquisitions

We have grown by making strategic acquisitions of producing properties in the Gulf of America. We seek opportunities where we can exploit additional drilling projects and reduce costs. In January 2024, we closed on the acquisition of rights, titles and interest in and to certain leases, wells and personal property in the central shelf region of the Gulf of America, among other assets, for $77.3 million, subject to customary purchase price adjustments. The transaction was funded with cash on hand. We also received a final settlement statement for our September 2023 acquisition of certain oil and natural gas producing assets in the central and eastern shelf region of the Gulf of America and recorded an additional $3.3 million of oil and natural gas properties.

Any future acquisitions are subject to the completion of satisfactory due diligence, the negotiation and resolution of significant legal issues, the negotiation, documentation and completion of mutually satisfactory definitive agreements among the parties, the consent of our lenders, our ability to finance the acquisition and approval of our board of directors. We cannot guarantee that any such potential transaction would be completed on acceptable terms, if at all.

Asset Retirement Obligations

We have obligations to plug and abandon wells, remove platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. During 2024, we paid $39.7 million related to these obligations. Our ARO estimates as of December 31, 2024 and 2023 were $548.8 million and $498.8 million, respectively. As our ARO estimates are for work to be performed in the future, and in the case of our non-current ARO, extend from one-to-many years in the future, the timing and amount of actual expenditures could be substantially different than our estimates. See Part I, Item 1A. *Risk Factors* and *Financial Statements and Supplementary Data – Note 4 – Asset Retirement Obligations* under Part II, Item 8 in this Form 10-K for additional information regarding our ARO.

Debt

As of December 31, 2024, we have $399.1 million in aggregate principal amount of long-term debt outstanding, with $28.7 million in aggregate principal coming due over the next twelve months.

On January 28, 2025, we issued $350.0 million of 10.75% Notes. The 10.75% Notes were issued at par and mature on February 1, 2029. We also terminated the Credit Agreement and used the net proceeds from the issuance of the 10.75% Notes and cash on hand to repay in full all outstanding amounts owed under the Term Loan and the 11.75% Notes outstanding.

On January 28, 2025, in conjunction with the issuance of the 10.75% Notes, we entered into the New Credit Agreement which provides us a revolving credit and letter of credit facility with initial bank lending commitments of $50.0 million with a letter of credit sublimit of $10.0 million. The New Credit Agreement matures on July 28, 2028.

For additional information about our long-term debt, see Part II, Item 8. *Financial Statements and Supplementary Data – Note 5 – Debt* and *Note 19 – Subsequent Events* of this Annual Report.

Dividends

In November 2023, we announced that our board of directors approved the implementation of a quarterly cash dividend payable to holders of common stock. During 2024, we have paid cash dividends totaling approximately $6.0 million to holders of our common stock. The amount and frequency of future dividends is subject to the discretion of our board of directors and primarily depends on earnings, capital expenditures, debt covenants and various other factors. For additional information about our dividends, see Part II, Item 8. *Financial Statements and Supplementary Data – Note 7 – Stockholders' Equity and Note 19 – Subsequent Events* of this Annual Report.

Contractual Obligations and Commitments

Our material cash commitments from known contractual and other obligations consist primarily of obligations for debt and related interest, operating leases, ARO and other obligations as part of normal operations. Certain amounts included in our contractual obligations as of December 31, 2024 are based on our estimates and assumptions about these obligations, including their duration, anticipated actions by third parties and other factors.

See *Financial Statements and Supplementary Data – Note 5 – Debt* under Part II, Item 8 in this 10-K for information regarding scheduled maturities of our debt. See *Financial Statements and Supplementary Data – Note 10 – Leases* under Part II, Item 8 in this 10-K for information regarding scheduled maturities of our operating leases.

As of December 31, 2024, we had expected cash payments for estimated interest on our long-term debt of $10.1 million payable within the next twelve months and $10.2 million payable through the maturity dates of our long-term debt.

We entered into a drilling contract during 2023. As of December 31, 2024, we anticipate that rig preparation work will begin in the fourth quarter of 2025 and drilling will begin in March 2026. We expect the total obligation under the contract to be approximately $9.9 million.

As of December 31, 2024, we had obligations for estimated fees for surety bonds related to obligations under certain purchase and sale agreements and for supplemental bonding for plugging and abandonment of $6.7 million payable in the next twelve months and $80.3 million through the estimated timing of the plugging and abandonment obligation occurs. The amounts are based on current market rates and conditions for these types of bonds and are subject to change. Excluded are potential increases in surety bond requirements which cannot be determined.

Additionally, we have obligations related to estimates of minimum quantities obligations for certain pipeline contracts which were assumed in conjunction with the purchase of an interest in the Heidelberg field of $0.6 million in the next twelve months and $1.0 million through the term of the contracts.

We have obligations under joint interest arrangements related to commitments that have not yet been incurred. In these instances, we are obligated to pay, according to our interest ownership, a portion of exploration and development costs, and operating costs, which potentially could be offset by our interest in future revenue from these non-operated properties. We also have obligations to plug and abandon well bores, remove platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations for future commitments cannot be determined due to the variability of factors involved.

CRITICAL ACCOUNTING ESTIMATES

An accounting policy is deemed to be critical if the nature of the estimate or assumption it incorporates is subject to a material level of judgment related to matters that are highly uncertain and changes in those estimates and assumptions are reasonably likely to materially impact our consolidated financial statements. These estimates reflect our best judgment about current, and for some estimates, future, economic and market conditions and their potential effects based on information available as of the date of these financial statements. Our most significant accounting policies are discussed in *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K.

We believe that the following are the critical accounting estimates used in the preparation of our consolidated financial statements for the year ended December 31, 2024. There are other items within our consolidated financial statements that require estimation and judgment, but they are not deemed critical as defined above.

Accounting for Oil and Natural Gas Properties

We account for our oil and natural gas operations using the full cost method of accounting. Under this method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the internal costs directly related to acquisition, development and exploration activities, asset retirement costs, and capitalized interest. Under the full cost method, dry hole costs, geological and geophysical costs, and overhead costs directly related to these activities are capitalized into the full cost pool, which is subject to amortization and assessed for impairment on a quarterly basis through a ceiling test calculation as discussed below.

Our rate of recording depletion expense is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record depletion expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices for oil, NGLs and natural gas, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2024, a five percent positive revision to proved reserves would decrease the depletion rate by approximately $0.09 per Mcfe and a five percent negative revision to proved reserves would increase the depletion rate by approximately $0.10 per Mcfe.

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our Consolidated Balance Sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings in the period of occurrence and could result in lower amortization expense in future periods.

The PV-10 of our estimated proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil, NGL and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, it is possible that write-downs of our oil and natural gas properties could occur in the future. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Using the first-day-of-the-month average for the 12-months ended December 31, 2024 of the WTI oil spot price of $76.32 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first-day-of-the-month average for the 12-months ended December 31, 2024 of the Henry Hub natural gas price of $2.13 per MMBtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials, our ceiling test calculation did not generate an impairment at December 31, 2024. Additionally, a 10% reduction in PV-10 at December 31, 2024, while all other factors remained constant, would also not have generated an impairment.

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 Reserve Quantities

Proved oil, NGL and natural gas reserves are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board. 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 our independent petroleum consultant, NSAI.

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 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.

Asset Retirement Obligations

We have significant obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We have obligations to plug and abandon all wells, remove our platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. Estimating the future restoration and removal cost requires us to make estimates and judgments because the removal obligations may be many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

We accrue a liability with respect to these obligations based on our estimates of the timing and the fair value of an obligation to replace, remove or retire the associated assets. After initial recording, the liability is accreted to its future estimated value using an assumed cost of funds.

In estimating the liability associated with our AROs, we utilize several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. To the extent future revisions to these estimates impact the value of our abandonment liability, a corresponding adjustment is made to our oil and natural gas property balance.

Income Taxes

Our income tax expense and deferred tax assets and liabilities reflect management's best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining consolidated income tax expense.

Deferred income taxes arise from temporary differences between the book carrying amounts and the tax basis of assets and liabilities, which will result in taxable or deductible amounts in the future. In evaluating our ability to recover our deferred tax assets, we consider all available positive and negative evidence including scheduled reversals of deferred tax liabilities, projected future taxable income, tax–planning strategies and results of recent operations. In projecting future taxable income, we begin with historical results adjusted for changes in accounting policies and incorporate assumptions, including the amount of future U.S. federal and state pretax operating income, the reversal of temporary differences and the implementation of feasible and prudent tax–planning strategies. These assumptions require significant judgment about the forecasts of future taxable income and are consistent with the plans and estimates we use to manage the underlying business.

As of December 31, 2024, we have federal net operating loss ("NOL") carryforwards of $51.5 million that do not expire, state NOL carryforwards of $104.1 million that expire on various dates from 2026 through 2043 and interest expense limitation carryforwards that do not expire. We believe that it is more likely than not that the benefit from certain of these carryforwards will not be realized. In recognition of this risk, we have provided a valuation allowance of $29.2 million on the deferred tax assets related to these carryforwards. If our assumptions change and we determine that we will be able to realize these carryforwards, the tax benefits related to any reversal of the valuation allowance on deferred tax assets as of December 31, 2024 would be recognized as a reduction of income tax expense.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the normal course of business, we are exposed to certain market risks that are inherent to the business of exploration and development of oil and natural gas. We may enter into derivative contracts to manage or reduce market risk, but we do not enter into derivative contracts for speculative purposes.

We do not designate our derivative contracts as hedges for accounting purposes. Accordingly, the changes in the fair value of these derivative contracts are recognized currently in earnings.

Commodity Price Risk

Our major market risk exposure is the fluctuation of prices for oil, NGLs and natural gas. These fluctuations have a direct impact on our revenues, earnings and cash flow. For example, assuming a 10% decline in our average realized oil, NGL and natural gas sales prices in 2024 and assuming no other items had changed, our revenue would have decreased by approximately $51.5 million in 2024. This amount would be representative of the effect on operating cash flows under these price change assumptions.

We have attempted to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas production through the use of swaps, purchased calls and purchased puts. Our derivatives will not mitigate all the commodity price risks of our forecasted sales of natural gas production and, as a result, we will be subject to commodity price risks on our remaining forecasted production.

The following table summarizes the historical results of our hedging activities:

	Year Ended December 31,	
	2024	**2023**
Natural Gas ($/Mcf)		
Average realized sales price, before the effects of derivative settlements	$ 2.65	$ 2.93
Effects of realized commodity derivatives	0.08	(0.11)
Average realized sales price, including realized commodity derivatives	$ 2.73	$ 2.82

Interest Rate Risk

As of December 31, 2024, our interest rate risk exposure is mitigated as of result of fixed interest rates on all our long-term debt outstanding. Should we ever have amounts outstanding under our New Credit Agreement, we would be subject to some interest rate risk exposure, as our New Credit Agreement has a variable interest rate per annum, which, at our option, is equal to either (a) an adjusted rate based on the Secured Overnight Financing Rate ("SOFR") plus an applicable margin that varies from 3.750% to 4.750% depending on the utilization of the New Credit Agreement or (b) a base rate plus an applicable margin that varies from 2.750% to 4.750%, such base rate calculated based on the highest of (i) the federal funds effective rate plus ½ of 1.0%, (ii) the U.S. Prime Rate and (iii) an adjusted SOFR rate for a 1-month interest period plus 1.0%. We do not have any derivative contracts related to interest rates as of December 31, 2024.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

W&T OFFSHORE, INC. AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated 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. Accordingly, even effective internal control over financial reporting can only provide reasonable assurance of achieving their control objectives.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework).

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2024 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The effectiveness of our internal control over financial reporting as of December 31, 2024 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of W&T Offshore Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of W&T Offshore Inc. 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 4, 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 4, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of W&T Offshore, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of W&T Offshore, Inc. and subsidiaries (the "Company") as of December 31, 2024, the related consolidated statements of operations, changes in shareholders' (deficit) equity, and cash flows for the year 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 the results of its operations and its cash flows the year 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 4, 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 Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Oil and Natural Gas Property and Depletion — Oil and Natural Gas Reserve Quantities — Refer to Note 1 to the financial statements

Critical Audit Matter Description

The Company uses the full cost method of accounting for its oil and natural gas properties. The Company’s proved oil and natural gas properties are depleted using the units of production method and are evaluated for impairment by the ceiling test calculation, utilizing the Company’s estimate of proved reserves in accordance with the rules established by the SEC and the Financial Accounting Standards Board. The Company’s estimate of proved reserves requires management to make significant estimates and assumptions related to the future rates of production, the future development expenditures associated with proved undeveloped reserves, and the timing of development expenditures and the intention to develop proved undeveloped reserves within the five-year development period (unless specific circumstances justify a longer period) as prescribed by SEC guidelines. The Company engages an independent reservoir engineering firm, management's specialist, to estimate oil and natural gas quantities using these assumptions and engineering data. Changes in these assumptions or engineering data could have a significant impact on the amount of depletion and impairment recorded for the Company's proved oil and natural gas properties.

Given the significant judgments made by management and management's specialist, performing audit procedures to evaluate the Company's estimated proved reserves, including management's estimates and assumptions related to future rates of production, future development expenditures, and the timing of such development expenditures within the five-year development period (or the justification of applying a longer development period), 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 to evaluate management's significant judgments and assumptions related to estimated proved reserves included the following, among others:

- We tested the effectiveness of controls over the reserve report, including those over management's estimation of future development expenditures, management's evaluation of the feasibility of their development plan and their adherence to SEC guidelines when classifying future locations within proved undeveloped reserves, and management's review of the report compiled by the independent reservoir engineering firm.

- We evaluated the reasonableness of management's development plan by comparing the forecasts to:
  - Historical conversions of proved undeveloped oil and natural gas reserves into proved developed oil and natural gas reserves.
  - Internal communications to management and the Board of Directors.
  - Prior year reserve reports to evaluate whether the forecasted date of development for each proved undeveloped location is within five years of the date of its original inclusion in proved reserves.
  - The facts and circumstances for the inclusion of any proved undeveloped locations with a development period longer than five years.
  - The financial ability of the Company to execute its drilling program.

- We evaluated the reasonableness of management's estimate of future development expenditures by comparing the estimate to:
  - Historical development of similar wells, including location of the well.
  - Internal data and internal communications to management.
  - Approval for expenditures.

- We evaluated the reasonableness of management's estimated reserve quantities by performing the following:
  - Evaluating the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm.
  - Performing analytical procedures on the reserve quantities developed by management's specialist.

Asset Retirement Obligations – Refer to Notes 1 and 4 to the financial statements

Critical Audit Matter Description

The Company has obligations to plug and abandon well bores, remove platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. The Company records a separate liability for the present value of an asset retirement obligation based on the estimated timing and amount to replace, remove or retire the associated assets, with an offsetting increase to oil and natural gas property costs. Several assumptions are utilized to estimate the asset retirement obligation liability, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. After initial recording, the liability is accreted to its future estimated value. If necessary, adjustments are made to the liability based on changes in expected future decommissioning costs. The estimation of the asset retirement obligation requires significant judgment given the magnitude of the expected decommissioning costs and uncertainty related to the timing of when the decommissioning work will be performed. Total asset retirement obligations as of December 31, 2024 are $548.8 million, with $46.3 million classified as a current liability and $502.5 million classified within long-term liabilities.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's asset retirement obligations, including management's estimates and assumptions related to future decommissioning costs and the expected timing of such future decommissioning costs, 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 to evaluate management's significant judgments and assumptions related to asset retirement obligations included the following, among others:

- We tested the effectiveness of controls over asset retirement obligations, including those over the estimation of the future decommissioning costs and the expected timing of such future decommissioning costs.

- We evaluated the reasonableness of management's estimate of future decommissioning costs by comparing the estimate to:
  - Historical decommissioning costs incurred.
  - Internal data and internal communications to management.
  - Approval for expenditures.

- We evaluated the reasonableness of management's expected timing of its future retirement obligations by comparing such dates to assumptions used in other areas, including the remaining well useful lives used in the estimation of oil and natural gas reserves.

/s/ DELOITTE & TOUCHE LLP

Houston, TX
March 4, 2025

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

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of W&T Offshore, Inc. and subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of W&T Offshore, Inc. and subsidiaries (the Company) as of December 31, 2023, the related consolidated statements of operations, changes in shareholders' (deficit) equity and cash flows for each of the two years in the period ended December 31, 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

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

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

/s/ Ernst & Young, LLP

We have served as the Company's auditor from 2000 to 2024.
Houston, Texas
March 6, 2024

W&T Offshore, Inc.
Consolidated Balance Sheets
(In thousands)

	December 31, 2024	December 31, 2023
Assets		
Current assets:		
Cash and cash equivalents	$ 109,003	$ 173,338
Restricted cash	1,552	4,417
Accounts receivable:		
Oil, natural gas liquids and natural gas sales	63,558	52,080
Joint interest, net	25,841	15,480
Other	—	2,218
Prepaid expenses and other current assets	18,504	17,447
Total current assets	218,458	264,980
Oil and natural gas properties and other, net	777,741	749,056
Restricted deposits for asset retirement obligations	22,730	22,272
Deferred income taxes	48,808	38,774
Other assets	31,193	38,923
Total assets	$ 1,098,930	$ 1,114,005
Liabilities and Shareholders' (Deficit) Equity		
Current liabilities:		
Accounts payable	$ 83,625	$ 78,857
Accrued liabilities	33,271	31,978
Undistributed oil and natural gas proceeds	53,131	42,134
Advances from joint interest partners	2,443	2,962
Current portion of asset retirement obligations	46,326	31,553
Current portion of long-term debt, net	27,288	29,368
Total current liabilities	246,084	216,852
Asset retirement obligations	502,506	467,262
Long-term debt, net	365,935	361,236
Other liabilities	16,182	19,420
Commitments and contingencies	20,800	18,043
Shareholders' (deficit) equity:		
Preferred stock: $0.00001 par value; 20,000 shares authorized; no shares issued	—	—
Common stock: $0.00001 par value; 400,000 shares authorized; 150,243 shares and 149,450 shares issued, respectively	2	1
Additional paid-in capital	595,407	586,014
Retained deficit	(623,819)	(530,656)
Treasury stock: 2,869 shares, at cost	(24,167)	(24,167)
Total shareholders' (deficit) equity	(52,577)	31,192
Total liabilities and shareholders' (deficit) equity	$ 1,098,930	$ 1,114,005

See accompanying Notes to Consolidated Financial Statements.

W&T Offshore, Inc.
Consolidated Statements of Operations
(In thousands, except per share amounts)

	Year Ended December 31,		
	2024	**2023**	**2022**
Revenues:			
Oil	$ 395,620	$ 381,389	$ 524,274
NGLs	27,978	32,446	56,964
Natural gas	90,877	110,158	323,831
Other	10,786	8,663	15,928
Total revenues	525,261	532,656	920,997
Operating expenses:			
Lease operating expenses	281,488	257,676	224,414
Gathering, transportation and production taxes	28,177	26,250	35,128
Depreciation, depletion, and amortization	143,025	114,677	107,122
Asset retirement obligations accretion	32,374	29,018	26,508
General and administrative expenses	82,391	75,541	73,747
Total operating expenses	567,455	503,162	466,919
Operating (loss) income	(42,194)	29,494	454,078
Interest expense, net	40,454	44,689	69,441
Derivative (gain) loss, net	(3,589)	(54,759)	85,533
Other expense, net	18,071	5,621	14,295
(Loss) income before income taxes	(97,130)	33,943	284,809
Income tax (benefit) expense	(9,985)	18,345	53,660
Net (loss) income	$ (87,145)	$ 15,598	$ 231,149
Net (loss) income per common share:			
Basic	$ (0.59)	$ 0.11	$ 1.61
Diluted	(0.59)	0.11	1.59
Weighted average common shares outstanding:			
Basic	147,133	146,483	143,143
Diluted	147,133	148,302	145,090

See accompanying Notes to Consolidated Financial Statements.

W&T Offshore, Inc.
Consolidated Statements of Changes in Shareholders' (Deficit) Equity
(In thousands)

	Common Stock		Additional Paid-In Capital	Retained Deficit	Treasury Stock		Total Shareholders' (Deficit) Equity
	Shares	Value			Shares	Value	
Balances at December 31, 2021	142,863	$ 1	$ 552,923	$ (775,937)	2,869	$ (24,167)	$ (247,180)
Share-based compensation	—	—	7,922	—	—	—	7,922
Shares withheld related to net settlement of equity awards	—	—	(715)	—	—	—	(715)
Share-based compensation common stock issuances	299	—	—	—	—	—	—
Net proceeds from issuance of common stock	2,971	—	16,458	—	—	—	16,458
Net income	—	—	—	231,149	—	—	231,149
Balances at December 31, 2022	146,133	1	576,588	(544,788)	2,869	(24,167)	7,634
Cash dividends	—	—	—	(1,466)			(1,466)
Share-based compensation	—	—	10,383	—	—	—	10,383
Shares withheld related to net settlement of equity awards	—	—	(957)	—	—	—	(957)
Share-based compensation common stock issuances	448	—	—	—	—	—	—
Net income	—	—	—	15,598	—	—	15,598
Balances at December 31, 2023	146,581	1	586,014	(530,656)	2,869	(24,167)	31,192
Cash dividends	—	—	—	(6,018)	—	—	(6,018)
Share-based compensation	—	—	10,192	—	—	—	10,192
Shares withheld related to net settlement of equity awards	—	—	(799)	—	—	—	(799)
Share-based compensation common stock issuances	793	1	—	—	—	—	1
Net loss	—	—	—	(87,145)	—	—	(87,145)
Balances at December 31, 2024	147,374	$ 2	$ 595,407	$ (623,819)	2,869	$ (24,167)	$ (52,577)

See accompanying Notes to Consolidated Financial Statements.

W&T Offshore, Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2024	2023	2022
Operating activities:			
Net (loss) income	$ (87,145)	$ 15,598	$ 231,149
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	175,399	143,695	133,630
Share-based compensation	10,192	10,383	7,922
Amortization and write-off of debt issuance costs	4,562	6,980	7,551
Derivative (gain) loss, net	(3,589)	(54,759)	85,533
Derivative cash receipts (settlements), net	4,527	(8,932)	(41,880)
Derivative cash premium payments	—	—	(46,111)
Deferred income (benefit) taxes	(10,077)	18,485	45,184
Changes in operating assets and liabilities:			
Accounts receivable	(19,621)	12,586	(15,482)
Prepaid expenses and other current assets	(1,450)	(2,712)	31,906
Accounts payable, accrued liabilities and other	26,433	7,972	(23,647)
Asset retirement obligation settlements	(39,692)	(33,970)	(76,225)
Net cash provided by operating activities	59,539	115,326	339,530
Investing activities:			
Investment in oil and natural gas properties and equipment	(37,357)	(41,813)	(43,526)
Acquisition of property interests	(80,635)	(27,384)	(51,474)
Purchase of corporate aircraft	—	(8,983)	—
Purchases of furniture, fixtures and other	(185)	(3,428)	(80)
Net cash used in investing activities	(118,177)	(81,608)	(95,080)
Financing activities:			
Proceeds from issuance of 11.75% Notes Senior Second Lien Notes	—	275,000	—
Repayment of 9.75% Second Senior Lien Notes	—	(552,460)	—
Repayments of Term Loan	—	(33,741)	(42,959)
Repayments of TVPX Loan	(1,100)	(733)	—
Debt issuance costs	(762)	(7,380)	(1,675)
Net proceeds from issuance of common stock	—	—	16,458
Payment of dividends	(5,902)	(1,466)	—
Other	(798)	(957)	(716)
Net cash used in financing activities	(8,562)	(321,737)	(28,892)
Change in cash, cash equivalents and restricted cash	(67,200)	(288,019)	215,558
Cash, cash equivalents and restricted cash, beginning of year	177,755	465,774	250,216
Cash, cash equivalents and restricted cash, end of period	$ 110,555	$ 177,755	$ 465,774

See accompanying Notes to Consolidated Financial Statements.

W&T Offshore, Inc.
Notes to Consolidated Financial Statements

NOTE 1 — BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

W&T Offshore, Inc. (with subsidiaries referred to herein as the “Company”) is an independent oil, NGL and natural gas producer with substantially all of its operations offshore in the Gulf of America. The Company is active in the exploration, development and acquisition of oil and natural gas properties. The Company operates in one reportable segment.

Basis of Presentation

The consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries and a variable interest entity in Monza Energy LLC (“Monza”), which is accounted for under the proportional consolidation method. All significant intercompany accounts and transactions have been eliminated.

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (the “SEC”) for annual financial information.

Certain reclassifications have been made to the prior year’s consolidated financial statements to conform to the current year’s presentation. On the Condensed Consolidated Balance Sheets, the Company has combined *Income tax payable* with *Accrued liabilities* and combined *Deferred income taxes* with *Other liabilities.* On the Condensed Consolidated Statements of Cash Flows, the Company has combined lines within operating cash flows and investing cash flows. These reclassifications had no effect on the Company’s results of operations, financial position or cash flows.

Use of Estimates

The preparation of 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 financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. While the Company believes that the estimates and assumptions used in the preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Cash Equivalents

The Company considers all highly liquid investments purchased with original or remaining maturities of three months or less at the date of purchase to be cash equivalents.

Restricted Cash

The Company maintains funds related to collateralized letters of credit.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable are recorded at historical cost, net of an allowance for credit losses, to reflect the net amounts to be collected. Receivables consist of sales of production to customers and joint interest billings. Payment of the Company’s accounts receivable is typically received within 30-60 days. At each reporting period, a loss methodology is used to determine the recoverability of material receivables using historical data, current market conditions and forecasts of future economic conditions to determine expected collectability.

Changes to the allowance for credit losses are as follows (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Allowance for credit losses, beginning of period	$ 11,130	$ 12,062	$ 10,046
Additional provisions for the year	473	123	3,085
Uncollectible accounts written off or collected	(1,189)	(1,055)	(1,069)
Allowance for credit losses, end of period	$ 10,414	$ 11,130	$ 12,062

Derivative Financial Instruments

The Company monitors its exposure to various business risks and uses derivative instruments to manage exposure to commodity price risk from sales of natural gas.

The Company has elected not to designate its derivative instruments as hedging instruments. Accordingly, the derivative instruments are recorded in the Consolidated Balance Sheets at fair value with settlements of such contracts, and changes in the unrealized fair value, recorded as *Derivative (gain) loss, net* in the Consolidated Statements of Operations in each period presented. Although the Company has master netting arrangements with its counterparties, the amounts recorded on the Consolidated Balance Sheets are on a gross basis.

The related cash flow impact of the Company's derivative instruments is reflected as cash flows from operating activities unless the derivative instrument contains a significant financing element, in which case the related cash flow impact is reflected as cash flows from financing activities in the Consolidated Statements of Cash Flows.

Oil and Natural Gas Properties and Other, Net

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under full cost accounting, all costs associated with the acquisition, exploration, development and abandonment of oil, NGL and natural gas reserves are capitalized into a full cost pool. Acquisition costs include costs incurred to purchase, lease or otherwise acquire properties. Exploration costs include costs of drilling exploratory wells and external geological and geophysical costs, which mainly consist of seismic costs. Development costs include the cost of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production, certain geological and geophysical costs and general and administrative costs are expensed in the period incurred.

Capitalized costs included in the amortization base are amortized using the units-of-production method based on production. Under this method, depreciation and depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost pool plus future development costs by net equivalent proved reserves at the beginning of the period.

Costs associated with unproved properties are excluded from the amortization base until the Company has made an evaluation that proved reserves exist or impairment has occurred. All items classified as unproved property are assessed, on an individual basis or as a group if properties are individually insignificant, on a periodic basis for possible impairment. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and whether the proved reserves can be developed economically. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. As of both December 31, 2024 and 2023, there were no unproved properties included in "Oil and natural gas properties, net."

Under the full-cost method of accounting, total capitalized costs of oil and natural gas properties (including capitalized ARO), net of accumulated depletion and amortization, may not exceed the ceiling limitation. A ceiling limitation calculation is performed quarterly. If the ceiling limitation is exceeded, a write-down of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge and is recorded as an expense on a pretax basis and separately disclosed. Any such write-downs are not recoverable or reversible in future periods. The Company did not record a ceiling test write-down during 2024, 2023 or 2022.

The ceiling test limit is calculated as: (i) the present value of estimated future net revenues from proved reserves, less estimated future development costs, discounted at 10%; (ii) plus the cost of unproved oil and natural gas properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base; and (iv) less related income tax effects. Estimated future net revenues used in the ceiling test for each period are based on current prices for each product, defined by the SEC as the unweighted average of first-day-of-the-month commodity prices over the prior twelve months for that period. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials.

Sales of proved and unproved oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

Other Property

Other property is stated at cost less accumulated depreciation and amortization, which is computed using the straight-line method based on the estimated useful lives of the respective assets, generally ranging from three to seven years. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. Repairs and maintenance costs are expensed in the period incurred. Significant improvements or betterments are capitalized if they extend the useful life of the asset.

Other property is reviewed for possible impairment whenever events or changes in circumstances indicate that estimated future net operating cash flows directly related to the asset or asset group including disposal value is less than the carrying amount of the asset or asset group. Impairment is measured as the excess of the carrying amount of the impaired asset or asset group over its fair value. The Company did not record any impairments related to other property during 2024, 2023 or 2022.

Asset Retirement Obligations

The Company has obligations to plug and abandon well bores, remove platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. The Company records a separate liability for the present value of an asset retirement obligation ("ARO") based on the estimated timing and amount to replace, remove or retire the associated assets, with an offsetting increase to oil and natural gas property costs. After initial recording, the liability accretes each period until it is settled, and the liability is removed and the capitalized ARO included in oil and natural gas properties is depreciated on a unit-of-production basis within the full cost pool. Both the accretion and depreciation are included in the consolidated statements of operations. If the Company incurs an amount different from the amount accrued for the associated ARO, the Company recognizes the difference as an adjustment to oil and natural gas properties.

In estimating the liability associated with its ARO, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect estimates of these future costs from period to period.

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 presented disaggregated in the Consolidated Statements of Operations by major product.

Revenue is recognized when the following five steps are completed: (1) the contract with the customer has been identified, (2) the performance obligation (promise) in the contract has been identified, (3) the transaction price has been determined, (4) the transaction price has been allocated to the performance obligations in the contract, and (5) revenue has been recognized when a performance obligation has been satisfied.

The Company records revenues from the sale of oil, NGLs and natural gas at the point in time that control of the product is transferred to the customer and collectability is probable. Revenue is measured based on contract consideration allocated to each unit of commodity and excludes amounts collected on behalf of third parties. Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction that are collected by the Company from a customer are excluded from revenue.

For sales of oil production, the Company recognizes revenue when control transfers at the delivery point at the net price received. Generally, this occurs when the Company (i) sells its oil production at the wellhead where control of the oil transfers to the customer or (ii) delivers its oil production to the customer at a contractual delivery point at which the customer takes custody, title and risk of loss of the product.

For sales of NGL and natural gas production, the Company evaluated its natural gas gathering and processing arrangements in place with midstream companies and has determined that control of the natural gas is transferred at the tailgate of the midstream entity's processing plant. Accordingly, revenues are presented on a gross basis for amounts expected to be received from the midstream company or third-party purchasers through the gathering and treating process. Any fees incurred to gather or process the natural gas are presented separately as *"Gathering, transportation and production taxes"* on the Consolidated Statements of Operations.

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 that 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.

Under its sales contracts, the Company invoices customers once its performance obligations have been satisfied and an unconditional right to consideration exists as of the balance sheet date. The Company recognized amounts due from contracts with customers of $63.6 million and $52.1 million as of December 31, 2024 and 2023, respectively, as *Accounts receivable – Oil, natural gas liquids and natural gas sales* on the Consolidated Balance Sheet.

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has elected the practical expedient permitting the Company not 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. For the Company's product sales that have a contract term greater than one year, the Company has elected the practical expedient permitting the Company not to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Share-Based Compensation

Share-based compensation cost is measured at the date of grant based on the calculated fair value of the award and is recognized over the period during which the recipient is required to provide service in exchange for the award. The compensation cost is determined based on awards ultimately expected to vest; therefore the Company has reduced the compensation cost for estimated forfeitures based on historical forfeiture rates. Forfeitures are estimated at the time of grant and revised, if necessary, in subsequent periods to reflect actual forfeitures.

Income Taxes

The Company's provision for income taxes includes U.S. state and federal taxes. Income taxes are recorded in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. The effects of changes in tax rates and laws on deferred tax balances are recognized in the period in which the new legislation is enacted. A valuation allowance is established on deferred tax assets when it is more likely than not that some portion or all the related tax benefits will not be realized.

Earnings Per Share

Basic earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of diluted common shares outstanding, which includes restricted stock units and performance stock units when the effect is dilutive.

Fair Value Measurements

Fair value is defined as the price the Company would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date. In the absence of active markets for the identical assets or liabilities, such measurements involve developing assumptions based on market observable data and, in the absence of such data, internal information that is consistent with what market participants would use in a hypothetical transaction that occurs at the measurement date.

Inputs to valuation techniques are classified as either observable (market data obtained from independent sources) or unobservable (the Company's market assumptions) within the following hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities.
- Level 2 – quoted process for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations whose inputs are observable or whose significant value drivers are observable.
- Level 3 – significant inputs to the valuation model are unobservable.

Valuation techniques are generally classified into three categories: the market approach; the income approach; and the cost approach. The selection and application of one or more of these techniques requires significant judgment and is primarily dependent upon the characteristics of the asset or liability, the principal (or most advantageous) market in which participants would transact for the asset or liability and the quality and availability of inputs.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents, accounts receivable and derivative instruments.

All the Company's cash and cash equivalents are maintained with several major financial institutions in the United States. Deposits with these financial institutions may exceed the amount of insurance provided on such deposits; however, the Company regularly monitors the financial stability of these financial institutions and believes that it is not exposed to any significant default risk.

The Company's customers consist primarily of major oil and natural gas companies, well-established oil and pipeline companies and independent oil and natural gas producers and suppliers. The majority of the Company's production is sold to customers under short-term contracts at market-based prices. In addition, the Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payment for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners are primarily independent oil and natural gas producers. The Company attempts to minimize credit risk exposure to its purchasers and joint interest owners through formal credit policies, monitoring procedures and letters of credit or guarantees when considered necessary.

In 2024, two customers accounted for approximately 44% and 12%, respectively, of the Company's receipts from sales of oil, NGL and natural gas. In 2023, two customers accounted for approximately 41% and 13%, respectively, of the Company's receipts from sales of oil, NGL and natural gas. In 2022, two customers accounted for approximately 31% and 13%, respectively, of the Company's receipts from sales of oil, NGL and natural gas. The loss of any of the customers above is not expected to result in a material adverse effect on the Company's ability to market future oil and natural gas production as replacement customers could be obtained in a relatively short period of time on terms, conditions and pricing substantially similar to those currently existing.

The Company is exposed to credit loss in the event of nonperformance by the derivative counterparties; however, the Company currently anticipates that the derivative counterparties will be able to fulfill their contractual obligations. The Company is not required to provide additional collateral to the derivative counterparties and does not require collateral from the derivative counterparties.

Recently Adopted Accounting Standards

The Company adopted Accounting Standards Update No. 2023-07, *Improvements to Reportable Segment Disclosures* ("ASU 2023-07") for the year ended December 31, 2024. ASU 2023-07 enhances the disclosures required for operating segments in the Company's annual and interim consolidated financial statements. The adoption of ASU 2023-07 did not have an impact on our consolidated financial statements but required additional disclosures (see *Note 15 – Segment Information*).

Accounting Standards to be Adopted

In December 2022, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update No. 2023-09, *Improvements to Income Tax Disclosures* ("ASU 2023-09"), which is intended to enhance transparency of income tax disclosures. ASU 2023-09 requires specified categories in the annual rate reconciliation that meet quantitative thresholds and further disaggregation of income taxes paid by jurisdictional categories (federal (national), state and foreign). ASU 2023-09, which allows for early adoption, is effective for the Company prospectively to all annual periods beginning after December 15, 2024. The Company is currently assessing the impact of ASU 2023-09; however, it is not expected to have a material impact on the Company's consolidated financial statements.

In November 2024, the FASB issued Accounting Standards Update No. 2024-03, *Disaggregation of Income Statement Expenses* ("ASU 2024-03") to enhance the disclosures required for certain expense captions in the Company annual and interim consolidated financial statements. ASU 2024-03 is effective prospectively or retrospectively for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The Company continues to evaluate the impact of ASU 2024-03 on its disclosures however, it is not expected to have a material impact on the Company's consolidated financial statements.

No other new accounting pronouncements issued or effective during 2024 have had or are expected to have a material impact on the Company's consolidated financial statements**.**

NOTE 2 — ACQUISITIONS

On December 13, 2023, the Company entered into a purchase and sale agreement to acquire rights, titles and interest in and to certain leases, wells and personal property in the central shelf region of the Gulf of America, among other assets, for $72.0 million. The transaction closed on January 16, 2024 for $77.3 million (including closing fees and other transaction costs) and was funded using cash on hand. The Company also assumed the related AROs associated with these assets.

On September 20, 2023, the Company entered into a purchase and sale agreement to acquire working interests in certain oil and natural gas producing assets in the central and eastern shelf region of the Gulf of America for $32.0 million, subject to normal and customary post-effective date adjustments (including net operating cash flow attributable to the properties from the effective date of June 1, 2023 to the close date). The transaction closed on September 20, 2023 for $27.4 million and was funded with cash on hand. The Company also assumed the related AROs associated with these assets. In February 2024, the Company received a final settlement statement for this acquisition and recorded an additional $3.3 million of oil and natural gas properties.

The Company determined that the assets acquired did not meet the definition of a business, and these transactions were accounted for as asset acquisitions. An acquisition qualifying as an asset acquisition requires, among other items, that the total purchase price, including transaction costs, be allocated to the assets acquired and liabilities based on their relative fair values. The fair value measurements of the oil and natural gas properties acquired and AROs assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and appropriate discount rates. These inputs required judgments and estimates by the Company's management at the time of the valuation. Transaction costs incurred on an asset acquisition are capitalized as a component of the assets acquired.

The following tables represent the Company's allocation of total purchase price consideration to the identifiable assets acquired and liabilities assumed based on the fair values on the date of acquisition (in thousands):

	January 2024	September 2023
Oil and natural gas properties and other, net	$ 94,970	$ 43,736
Asset retirement obligations	(17,647)	(16,352)
Allocated purchase price	$ 77,323	$ 27,384

NOTE 3 — RESTRICTED DEPOSITS FOR ARO

Restricted deposits for ARO consist of funds received from previous operators to cover future plugging and abandonment obligations of certain oil and natural gas properties. These deposits relate to the following fields (in thousands):

	December 31,	
	2024	2023
Main Pass 283/Viosca Knoll 734	$ 14,110	$ 13,887
South Marsh Island 73	7,752	7,756
Other	868	629
Total	22,730	22,272

NOTE 4 — ASSET RETIREMENT OBLIGATIONS

The changes in ARO were as follows (in thousands):

	Year Ended December 31, 2024	Year Ended December 31, 2023
Asset retirement obligations, beginning of period	$ 498,815	$ 466,430
Liabilities settled	(39,692)	(33,970)
Accretion expense	32,374	29,018
Liabilities acquired	17,647	16,352
Liabilities incurred	—	129
Revisions of estimated liabilities	39,688	20,856
Asset retirement obligations, end of period	548,832	498,815
Less: Current portion	(46,326)	(31,553)
Long-term	$ 502,506	$ 467,262

NOTE 5 — DEBT

The components of debt are presented in the following tables (in thousands):

	December 31, 2024	December 31, 2023
Term Loan:		
Principal	$ 114,159	$ 114,159
Unamortized debt issuance costs	(2,027)	(3,052)
Total	112,132	111,107
11.75% Senior Second Lien Notes due 2026:		
Principal	275,000	275,000
Unamortized debt issuance costs	(2,919)	(5,090)
Total	272,081	269,910
TVPX Loan:		
Principal	9,925	11,025
Unamortized discount	(771)	(1,294)
Unamortized debt issuance costs	(144)	(144)
Total	9,010	9,587
Total debt, net	393,223	390,604
Less current portion, net	(27,288)	(29,368)
Long-term debt, net	$ 365,935	$ 361,236

Term Loan

Aquasition LLC and Aquasition II LLC (collectively, the “Subsidiary Borrowers”), both indirect wholly owned subsidiaries of the Company, are parties to a credit agreement providing for a $215.0 million term loan (the “Term Loan”). The Term Loan bears interest at a fixed rate of 7.0% per annum (effective rate of 8.2% for 2024) and matures on May 19, 2028.

In March 2024, the Term Loan was amended to provide for (i) the deferral of $30.1 million of principal repayments during 2024; (ii) the resumption of principal repayments in the first quarter of 2025 with the option, but not obligation, to catch up on deferred amortization through excess cash flow sweep; (iii) the payment of cash interest each quarter on the remaining principal balance; (iv) the payment of an amendment fee of $0.2 million to be paid in four quarterly installments of $50,000 each, starting in the first quarter of 2024; and (v) the modification of the optional prepayment schedule as follows: redemption at 103% of par from May 2024 to May 2026, redemption at 102% of par from May

2026 up to May 2027, and 101% of par from May 2027 up to maturity in May 2028. The premium will be applicable to the aggregate principal amount outstanding at the time of any optional redemption.

The Term Loan is non-recourse to the Company and any subsidiaries other than the Subsidiary Borrowers and their parent and is secured by first lien security interests in the equity of the Subsidiary Borrowers and a first lien mortgage security interest and mortgages on certain assets of the Subsidiary Borrowers.

Subsequent to December 31, 2024, the Subsidiary Borrowers terminated the Term Loan and all outstanding obligations owed under the Term Loan were paid in full in connection with such termination. See *Note 19 – Subsequent Events* for additional information.

11.75% Senior Second Lien Notes due 2026

The Company's 11.75% Senior Second Lien Notes (the "11.75% Notes") were issued under an indenture dated January 27, 2023 (the "Indenture"). The 11.75% Notes mature on February 1, 2026 and interest is payable in arrears on February 1 and August 1.

The 11.75% Notes are secured by second-priority liens on the same collateral that is secured under the Credit Agreement. The estimated annual effective interest rate for 2024 on the 11.75% Notes is 12.8%, which includes amortization of debt issuance costs.

The Company may redeem the 11.75% Notes, in whole or in part, at redemption prices (expressed as percentages of the principal amount thereof) equal to 105.875% through July 31, 2025 and 100.000% on August 1, 2025 and thereafter, plus accrued and unpaid interest, if any, to the redemption date. The 11.75% Notes are guaranteed by the Guarantors.

Subsequent to December 31, 2024, the Company purchased for cash pursuant to a tender offer (the "Tender Offer"), such of its outstanding 11.750% Notes that were validly tendered (and not validly withdrawn) pursuant to the terms of the Tender Offer and elected to effect an optional redemption of the 11.75% Notes on August 1, 2025, and caused the satisfaction and discharge of the 2023 Indenture. See *Note 19 – Subsequent Events* for additional information.

TVPX Loan

In May 2023, the Company acquired a corporate aircraft from a company affiliated with and controlled by the Company's Chairman, Chief Executive Officer ("CEO") and President, Tracy W. Krohn. The terms of the transactions were reviewed and approved by the Audit Committee of the Company's board of directors. See *Note 17 – Related Parties*.

The purchase price of the aircraft was $19.1 million, which was paid using $9.0 million of the Company's cash on hand and through the assumption of an approximately $11.8 million amortizing loan (the "TVPX Loan"), not in its individual capacity but as owner trustee of the trust which holds title to the aircraft, a wholly owned indirect subsidiary of the Company, as the borrower. Using current market rates, the Company determined that the fair market value of the TVPX Loan was $10.1 million at the time of assumption.

The TVPX Loan bears a fixed interest rate of 2.49% per annum (effective rate of 9.4% for 2024) for a term of 41 months and requires monthly amortization payments of $91.7 thousand plus accrued interest, and a balloon payment of $8.0 million at the end of the loan term. The TVPX Loan is guaranteed by the Company on an unsecured basis.

Credit Agreement

The Company is party to a credit agreement (as amended from time to time, the "Credit Agreement") with Calculus Lending, LLC ("Calculus"), a company affiliated with and controlled by the Company's CEO, as sole lender. The Credit Agreement currently has a maturity date of January 31, 2025.

The Credit Agreement consists of a $100.0 million secured revolving credit facility, with borrowings limited to a borrowing base of $50.0 million. The Credit Agreement is secured by a first priority lien on substantially all of the Company's and its guarantor subsidiaries' assets, excluding those assets of the Subsidiary Borrowers.

Outstanding borrowings accrue interest at SOFR plus 6.0% per annum. Additionally, the Company is required to pay commitment fees based on the daily unused amount of the Credit Agreement at a rate of 3.0% per annum.

As of both December 31, 2024 and 2023, there were no borrowings outstanding under the Credit Agreement and no borrowings had been incurred under the Credit Agreement during 2024 or 2023.

Subsequent to December 31, 2024, the Company terminated the Credit Agreement. See *Note 19 – Subsequent Events* for additional information.

Maturities of Long-Term Debt

The maturities of the Company's principal amounts of long-term debt are as follows (in millions):

2025	$ 28.7
2026	309.3
2027	22.8
2028	38.3
2029	—
Thereafter	—
Total	$ 399.1

Covenants

The Company's debt agreements contain certain representations, warranties, covenants and other terms and conditions which are customary for agreements of these types. As of December 31, 2024, the Company was in compliance with all applicable covenants of the Indenture, the TVPX Loan and the Credit Agreement.

NOTE 6 — COMMITMENTS AND CONTINGENCIES

Commitments

As of December 31, 2024, the Company has $463.3 million of surety bonds outstanding related to contractual obligations, litigation appeals and decommissioning obligations pursuant to certain purchase and sale agreements. Certain of the surety bonds related to decommissioning obligations are subject to escalation, in amounts ranging from $30.0 million to $70.0 million. The Company is required to maintain this level of bonds until the properties are fully plugged, abandoned, and restored in accordance with applicable laws and regulations.

Total expenses related to these surety bonds, inclusive of the surety bonds in connection with the agreements described above, were $7.5 million, $7.4 million and $8.3 million during 2024, 2023 and 2022, respectively. Future surety bond costs may change due to a number of factors, including changes and interpretations of regulations by the BOEM, rates being charged in the marketplace, availability of bonding capacity in the marketplace and when obligations are completed.

In conjunction with the purchase of an interest in the Heidelberg field, the Company assumed contracts with certain pipeline companies that contain minimum quantities obligations that extend through 2028. The Company recognized expenses of $0.4 million, $1.0 million and $1.6 million for the difference between the quantities shipped and the minimum obligations during 2024, 2023 and 2022, respectively.

The Company entered into a drilling contract during 2023. As of December 31, 2024, the Company anticipates that rig preparation work will begin in the fourth quarter of 2025 and drilling will begin in March 2026. The Company expects the total obligation under the contract to be approximately $9.9 million.

Contingencies

Appeal with the Office of Natural Resources Revenue

In 2009, the Company recognized allowable reductions of cash payments for royalties owed to the Office of Natural Resources Revenue (the "ONRR") for transportation of its deepwater production through subsea pipeline systems owned by the Company. In 2010, the ONRR audited calculations and support related to this usage fee, and ONRR notified the Company that they had disallowed approximately $4.7 million of the reductions taken. As of December 31, 2024, the Company has accrued $5.0 million related to this matter, consisting of $4.7 million for the disallowed reductions and $0.3 million for estimated penalties. The Company disagrees with the position taken by the ONRR and filed an appeal with the ONRR.

The Company has continued to pursue its legal rights and, at present, the case is in front of the U.S. District Court for the Eastern District of Louisiana where both parties have filed cross-motions for summary judgment and opposition briefs. The Company has filed a Reply in support of its Motion for Summary Judgment, and the government has in turn filed its Reply brief. With briefing now completed, the Company is waiting for the district court's ruling on the merits.

ONRR Audit of Historical Refund Claims

In 2023, the Company received notification from the ONRR regarding results of an audit performed on the Company's historical refund claims taken on various properties for alleged royalties owed to the ONRR. The review process is ongoing, and the Company does not believe any accrual is necessary at this time.

Bonding Disputes

On August 14, 2024, the Company filed a complaint seeking declaratory relief (the "Original Complaint") in the U.S. District Court for the Southern District of Texas, Houston Division, against Endurance Assurance Corporation and Lexon Insurance Company (the "Sompo Sureties"), providers of government-required surety bonds that secure decommissioning obligations the Company may have with respect to certain oil and gas assets of the Company (the "Sompo Sureties Litigation"). As described in the Original Complaint, the Company has paid all negotiated premiums associated with the bonds issued by the Sompo Sureties prior to the Original Complaint and has not suffered a material change to its financial status. Despite this, the Sompo Sureties issued written demands to the Company requesting the Company provide collateral to the Sompo Sureties. On October 9, 2024, the Sompo Sureties filed an answer and counterclaim alleging breach of contract due to the Company's failure to provide the collateral demanded by the Sompo Sureties. The Sompo Sureties originally issued approximately $55.0 million in surety bonds on behalf of the Company. However, the BOEM cancelled a $13.1 million bond when the Company fulfilled its decommissioning obligations. Despite this, the Sompo Sureties have requested approximately $55.0 million in cash collateral.

On October 21, 2024, U.S. Specialty Insurance Company ("USSIC") filed a petition in the District Court of Harris County, Texas, alleging, among other things, breach of the indemnity agreement between the Company and USSIC and seeking to compel the Company to provide the collateral demanded by USSIC (the "USSIC Litigation"). On October 25, 2024, the Company filed a notice of removal with the District Court of Harris County, Texas, removing the case to U.S. District Court for the Southern District of Texas, Houston Division. USSIC has issued approximately $111.0 million in surety bonds on behalf of the Company and has requested $23.0 million in cash collateral.

On November 8, 2024, Pennsylvania Insurance Company a/k/a Applied Surety Underwriters ("Applied") filed a petition in the United States District Court for the Southern District of Texas, Houston Division, alleging, among other things, breach of the indemnity agreement between the Company and Applied and seeking to compel the Company to provide the collateral demanded by Applied and unpaid premiums of approximately $0.4 million (the "Applied Litigation"). Applied issued approximately $11.3 million in surety bonds on behalf of the Company and has requested approximately $11.3 million in cash collateral.

Also on November 8, 2024, United States Fire Insurance Company ("U.S. Fire" and, together with the Sompo Sureties, USSIC and Applied, the "Sureties") filed a petition in the United States District Court for the Southern District of Texas, Houston Division, alleging, among other things, breach of the indemnity agreement between the Company and U.S. Fire and seeking to compel the Company to provide the collateral demanded by U.S. Fire (the "U.S. Fire Litigation"). U.S. Fire claims to have issued approximately $93.5 million in surety bonds on behalf of the Company and has requested approximately $93.5 million in cash collateral.

The Sureties' aggregate collateral demands against the Company total approximately $183.7 million. In addition, Philadelphia Indemnity Insurance Company ("PIIC") separately made a collateral demand of $71 million. No legal action has been filed by PIIC as of the date hereof. The total aggregate collateral demanded by the Sureties and PIIC is approximately $254.7 million (the "Demanded Collateral").

On November 22, 2024, the court consolidated the Sompo Sureties Litigation, USSIC Litigation, the Applied Litigation, and the U.S. Fire Litigation (as consolidated, the "Sureties Litigation"). On December 11, 2024, as a result of the foregoing, the Company filed an amended complaint (the Original Complaint, as amended, the "Complaint") against the Sureties. The Complaint, in relevant part, seeks declaratory relief that (1) the Sureties may not enforce their indemnity agreements such that their action constitute an abuse of right; (2) the Sureties' interpretation of the indemnity agreements render the agreements illusory; (3) the Sureties may not make unreasonable demands for collateral; (4) the Sureties must accept reasonable collateral as offered by the Company; (5) no additional collateral is required of the Company; (6) the Sureties may not make joint demands for collateral that are inconsistent with those of each other such that the Company cannot comply with each demand; and (7) the Sureties' changed business model are not legitimate grounds to demand further collateral beyond that offered by the Company. The Company further asserts the following counterclaim against the Sureties: (1) violations of the Sherman Antitrust Act; (2) violations of the Texas Free Enterprise and Antitrust Act; (3) violations of the Texas Insurance Code Section 541; (4) tortious interference with existing contracts and prospective business relationships; and (5) conspiracy.

As a result of the Sureties Litigation, the Company may potentially be required to provide some or all of the Demanded Collateral, or the Company may be required to or choose to seek alternate bonding or financial assurance. The Company is seeking to negotiate a reasonable resolution with respect to collateral provision amongst the Sureties and other surety entities with conflicting or different collateral requests (such as PIIC).

In each of the above cases, the Company believes that compliance with the collateral demands of the applicable surety entity would be contrary to the demands of other entities that provide government-required surety bonds to the Company. In addition, the Company believes compliance with these collateral demands could prompt escalating collateral requirements. As a result of the foregoing litigation, the Company may be required to provide the collateral demanded by the surety entities, or the Company may be required to or choose to replace the surety bonds provided by the applicable surety with alternate bonding or financial assurance. All of the parties to the Sureties Litigation, as well as PIIC (who is not a party to the Sureties Litigation), agreed to mediate the case until the mediator declares an impasse. The Company is seeking to negotiate a reasonable resolution with respect to collateral provision amongst the surety entities and other surety entities with conflicting or different collateral requests. As of March 4, 2025, the mediation is ongoing.

To the extent that the Company is required to fulfil the collateral demands made by the surety entities, or in the event that other surety entities make additional collateral demands, the fulfilment of such demands could be significant and could impact the Company's liquidity.

Contingent Decommissioning Obligations

Certain counterparties in past divestiture transactions or third parties in existing leases that have filed for bankruptcy protection or undergone associated reorganizations may not be able to perform required abandonment obligations. Due to operation of law, the Company may be required to assume decommissioning obligations for those interests. The Company may be held jointly and severally liable for the decommissioning of various facilities and related wells. The Company no longer owns these assets, nor are they related to current operations.

During 2024, the Company incurred $16.4 million in costs related to these decommissioning obligations and reassessed the existing decommissioning obligations, recording an additional $20.9 million. As of December 31, 2024, the remaining loss contingency recorded related to the anticipated decommissioning obligations was $22.6 million.

Although it is reasonably possible that the Company could receive state or federal decommissioning orders in the future or be notified of defaulting third parties in existing leases, the Company cannot predict with certainty, if, how or when such orders or notices will be resolved or estimate a possible loss or range of loss that may result from such orders. However, the Company could incur judgments, enter into settlements or revise the Company's opinion regarding the outcome of certain notices or matters, and such developments could have a material adverse effect on the Company's results of operations in the period in which the amounts are accrued and the Company's cash flows in the period in which the amounts are paid. To the extent the Company does incur costs associated with these properties in future periods, the Company intends to seek contribution from other parties that owned an interest in the facilities.

Other Claims

In the ordinary course of business, the Company is a party to various pending or threatened claims and complaints seeking damages or other remedies concerning commercial operations and other matters. In addition, claims or contingencies may arise related to matters occurring prior to the Company's acquisition of properties or related to matters occurring subsequent to the Company's sale of properties. In certain cases, the Company has indemnified the sellers of properties acquired, and in other cases, has indemnified the buyers of properties sold. The Company is also subject to federal and state administrative proceedings conducted in the ordinary course of business including matters related to alleged royalty underpayments on certain federal-owned properties. Although the Company can give no assurance about the outcome of pending legal and federal or state administrative proceedings and the effect such an outcome may have, the Company believes that any ultimate liability resulting from the outcome of such proceedings, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on the consolidated financial position, results of operations or liquidity of the Company.

NOTE 7 — STOCKHOLDERS' EQUITY

At-the-Market Equity Offering

In March 2022, the Company filed a prospectus supplement related to the issuance and sale of up to $100.0 million of shares of common stock under the Company's at-the-market equity agreement (the "ATM agreement"). The designated sales agent is entitled to a placement fee of up to 3.0% of the gross sales price per share sold.

The Company did not sell any shares of common stock in connection with the ATM agreement during 2024 or 2023. During 2022, the Company sold an aggregate of 2,971,413 shares for an average price of $5.72 per share in connection with the ATM Offering and received proceeds, net of commissions and expenses, of $16.5 million.

Cash Dividends

In November 2023, the Company announced that its board of directors approved the implementation of a quarterly cash dividend. A summary of the dividends declared by the Company is as follows (in thousands, except per share amounts):

	Dividends per Common Share	Dividends Declared
2024		
Q4	$ 0.01	$ 1,510
Q3	0.01	1,518
Q2	0.01	1,483
Q1	0.01	1,507
2023		
Q4	0.01	1,466

On March 3, 2025, the Company's board of directors declared a regular quarterly dividend of $0.01 per share of common stock. The dividend is to be paid on March 24, 2025 to stockholders of record at the close of business on March 17, 2025.

NOTE 8 — SHARE-BASED COMPENSATION

The Company has a long-term incentive plan (the "Plan") for its eligible employees, non-employee directors and consultants that includes both cash and share-based compensation awards. The Plan is administered by the Compensation Committee of the board of directors. The Plan allows for the issuance of stock options, stock appreciation rights, restricted stock, restricted stock units ("RSUs"), bonus stock, dividend equivalents, or other awards related to stock, and awards may be paid in cash, stock, or any combination of cash and stock, as determined by the Compensation Committee.

As of December 31, 2024, the maximum number of shares of common stock available for issuance under the Plan is 10.0 million shares and 4.3 million shares remain available for grant. Shares subject to awards granted under the Plan that are subsequently canceled, forfeited or otherwise terminated without delivery of shares are available for future grant under the Plan. The Company's policy is to issue new shares when RSUs and performance stock units ("PSUs") are vested.

Restricted Stock Units

An RSU is an award where each unit represents the right to receive the value of one share of our common stock at the date of vesting. RSUs are subject to service conditions, and vest ratably over approximately three years or one year for RSUs granted to employees and non-employee directors, respectively.

A summary of activity related to RSUs is as follows:

	Restricted Stock Units	Weighted Average Grant Date Fair Value per Unit
Nonvested, beginning of period	2,408,196	$ 4.52
Granted	2,426,489	2.21
Vested	(1,088,208)	4.53
Forfeited	(239,429)	4.15
Nonvested, end of period	3,507,048	$ 2.93

The grant date fair value of RSUs granted during 2024, 2023 and 2022 was $5.4 million, $7.4 million and $6.1 million, respectively. The fair value of the RSUs that vested during 2024, 2023 and 2022 was $4.9 million, $2.5 million and $1.9 million, respectively, based on the closing price of the Company's common stock on the vesting date.

As of December 31, 2024, there was $4.0 million of total unrecognized compensation costs related to unvested RSUs which is expected to be recognized over a weighted average period of 1.3 years.

Performance Share Units

A performance share unit ("PSU") is an RSU award granted subject to performance criteria. The PSUs granted in 2024 are subject to performance criteria of total shareholder return and relative shareholder return (collectively, the "TSR PSUs") and cash return on capital employed (the "CROCE PSUs"). The performance period for the measurement of the performance goal began on January 1, 2024 and ends on December 31, 2026. To be eligible to receive the earned PSUs, employees must be employed from the grant date through December 31, 2026. Different levels of achievement across these metrics will affect the percentage of PSUs that the employee receives upon the satisfaction of the service requirement. The percentage of PSUs received upon vesting ranges from 0% to 200%.

The TSR PSUs will account for 60% of the target PSUs granted to employees. The TSR PSUs contain both a service condition and a market condition. The grant date fair value of the TSR PSUs was determined through the use of the Monte Carlo simulation method. This method requires the use of subjective assumptions such as the price and the expected volatility of the Company's stock and its self-determined Peer Group companies' stock, risk-free rate of return and cross-correlations between the Company and its Peer Group companies. Expected volatilities for the Company's and each peer company utilized in the model are estimated using a historical period consistent with the awards' remaining performance period as of the grant date. The risk-free interest rate is based on the yield on U.S. Treasury Constant Maturity for a term consistent with the remaining performance period. The valuation model assumes dividends, if any, are immediately reinvested.

The performance criteria for PSUs granted in 2023 and 2022 relates to the evaluation of the Company's total shareholder return ("TSR") ranking against peer companies' TSR over the applicable performance period and subject to service conditions through the vesting date. TSR is determined based on the change in the entity's stock price plus dividends and distributions for the applicable performance period. These PSUs are subject to an approximate three-year performance period and service conditions through the vesting date. The performance periods for the 2023 PSU grants and the 2022 PSU grants end on December 31, 2025 and December 31, 2024, respectively. These PSUs contain both a service condition and a market condition. The grant date fair value of these PSUs was also determined through the use of the Monte Carlo simulation method.

The following table summarizes the assumptions used to calculate the grant date fair value of the PSUs described above:

	Year Ended December 31,		
	2024	**2023**	**2022**
Expected term for performance period (in years)	2.4	2.6	2.6
Expected volatility	65.0 %	76.1 %	84.4 %
Risk-free interest rate	3.9 %	4.2 %	2.5 %

The CROCE PSUs will account for 40% of the target PSUs granted to employees in 2024. The CROCE PSUs contain both a service condition and a performance condition. The grant date fair value of the CROCE PSUs was determined using the closing stock price of the Company's common stock on the date of grant. The cumulative compensation cost that will be recognized will be equal to the grant date fair value of the awards deemed probable of vesting multiplied by the percentage of the requisite service period that has been rendered. Unlike the TSR PSUs, if the performance condition is not satisfied, any previously recognized compensation expense is reversed.

A summary of activity related to PSUs is as follows:

	Performance Share Units	Weighted Average Grant Date Fair Value per Unit
Nonvested, beginning of period	2,398,719	$ 7.38
Granted	1,405,587	2.47
Vested	—	—
Forfeited	(1,340,909)	9.40
Nonvested, end of period	2,463,397	$ 3.48

The grant date fair value of PSUs granted during 2024, 2023 and 2022 was $3.5 million, $6.3 million and $14.2 million, respectively. No PSUs vested during 2024. The fair value of the PSUs that vested during 2023 and 2022 was $0.7 million and $0.1 million, respectively, based on the closing price of the Company's common stock on the vesting date.

As of December 31, 2024, there was $3.6 million of total unrecognized compensation costs related to unvested PSUs which is expected to be recognized over a weighted average period of 1.5 years.

Share-Based Compensation Expense

Compensation cost for share-based payments to employees is recognized using an accelerated attribution method over the period during which the recipient is required to provide service in exchange for the award. Compensation cost is based on the fair value of the equity instrument on the date of grant. Forfeitures are estimated during the vesting period, resulting in the recognition of compensation cost only for those awards that are expected to actually vest. Estimated forfeitures are adjusted to actual forfeitures when the award vests. All RSUs and PSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restricted period.

The following table presents the compensation expenses included in *General and administrative expenses* in the Consolidated Statements of Operations (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Restricted stock units	$ 4,433	$ 4,477	$ 4,192
Performance share units	5,759	5,836	3,504
Restricted shares	—	70	226
Total	$ 10,192	$ 10,383	$ 7,922

NOTE 9 — EMPLOYEE BENEFIT PLAN

The Company maintains a defined contribution benefit plan (the “401(k) Plan”) for all eligible employees. The Company matches employee contributions 100% of each participant’s contribution up to a maximum of 6% of the participant’s eligible compensation, subject to limitations imposed by the IRC. The 401(k) Plan provides 100% vesting in Company match contributions on a pro rata basis over five years of service (20% per year). Expenses relating to the 401(k) Plan were $3.3 million, $2.9 million, and $2.4 million for 2024, 2023 and 2022, respectively.

NOTE 10 — LEASES

The Company has entered into various non-cancellable operating leases for certain of the Company’s offices, land and various pipeline right-of-way contracts. The Company determines if an arrangement is a lease, or contains a lease, at inception and establishes a right-of-use (“ROU”) asset and lease liability based on the Company’s assumptions of the term, inflation rates and incremental borrowing rates. The Company has elected the short-term practical expedient to not apply the recognition requirements to short-term leases with a term of twelve months or less. The Company has also elected the practical expedient to not separate lease and nonlease components.

The Company’s operating leases include options to extend the lease term, at the Company’s discretion, for an additional two to ten years. The Company is not, however, reasonably certain that it will exercise any of the options to extend these leases and as such, the options have not been included in the remaining lease terms.

The amounts disclosed herein primarily represent costs associated with properties operated by the Company that are presented on a gross basis and do not reflect the Company’s net proportionate share of such amounts. A portion of these costs have been or will be billed to other working interest owners where applicable. The Company’s share of these costs is included in oil and natural gas properties, lease operating expense or general and administrative expense, as applicable.

The components of lease costs were as follows (in thousands):

	December 31,		
	2024	2023	2022
Operating lease costs, excluding short-term leases	$ 1,718	$ 1,670	$ 1,579
Short-term lease cost	143	58	2,957
Variable lease cost [(1)]	951	765	647
Total lease cost	$ 2,812	$ 2,493	$ 5,183

(1) Variable lease costs primarily represent differences between minimum lease payment obligations and actual operating charges incurred by the Company related to long-term operating leases.

The present value of the fixed lease payments recorded as the Company's ROU assets and operating lease liabilities, adjusted for initial direct costs and incentives, are as follows (in thousands):

	December 31,	
	2024	2023
ROU assets – Other assets	$ 10,045	$ 10,515
Lease liability:		
Accrued liabilities	$ 1,522	$ 1,455
Other liabilities	10,390	10,803
Total lease liability	$ 11,912	$ 12,258

The weighted average remaining lease term and discount rate related to the Company's operating leases are as follows (in thousands):

	December 31,		
	2024	2023	2022
Weighted average remaining lease term	11.5 years	12.1 years	13.1 years
Weighted average discount rate	10.3 %	10.3 %	10.1 %

Supplemental cash flow information related to the Company's operating leases are as follows (in thousands):

	December 31,		
	2024	2023	2022
Operating cash outflow from operating leases	$ 1,595	$ 1,713	$ 1,224
Right-of-use assets obtained in exchange for new operating lease liabilities	$ —	$ 559	$ —

As of December 31, 2024, the maturities of the liabilities related to the Company's operating leases are as follows (in thousands):

2025	$ 2,164
2026	1,625
2027	1,658
2028	1,712
2029	3,980
Thereafter	8,908
Total lease payments	20,047
Less: imputed interest	(8,135)
Total	$ 11,912

NOTE 11 — FINANCIAL INSTRUMENTS

The Company’s financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, accrued liabilities, derivative instruments and debt. Except for derivative instruments and debt, the carrying amount of the Company’s financial instruments approximates fair value due to the short-term, highly liquid nature of these instruments.

Derivative Instruments

The following table reflects the contracted volumes and weighted average prices under the terms of the Company’s open Henry Hub (NYMEX) natural gas derivative contracts as of December 31, 2024:

Period	Instrument Type	Average Daily Volumes *(Mmbtu)*	Total Volumes *(Mmbtu)*	Weighted Strike Price *($/Mmbtu)*	Weighted Put Price *($/Mmbtu)*	Weighted Call Price *($/Mmbtu)*
Jan 2025 - Mar 2025	calls	62,000	5,580,000	$ —	$ —	$ 5.50
Jan 2025 - Mar 2025	swaps	63,333	5,700,000	$ 2.72	$ —	$ —
Apr 2025 - Dec 2025	puts	62,182	17,100,000	$	$ 2.27	$ —
Jan 2026 - Dec 2026	puts	55,890	20,400,000	$ —	$ 2.35	$ —
Jan 2027 - Dec 2027	puts	52,603	19,200,000	$ —	$ 2.37	$ —
Jan 2028 - Apr 2028	puts	49,587	6,000,000	$ —	$ 2.50	$ —

The fair value of the Company’s derivative financial instruments was recorded in the Consolidated Balance Sheets as follows (in thousands):

	December 31, 2024	December 31, 2023
Prepaid expenses and other current assets	$ 868	$ 1,180
Other assets	4,150	10,068
Accrued liabilities	3,731	6,267
Other liabilities	—	2,756

The Company measures the fair value of its derivative instruments on a recurring basis by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The income approach converts expected future cash flows to a present value amount based on market expectations. The inputs used for the fair value measurement of derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads and published commodity future prices.

The impact of commodity derivative contracts on the Consolidated Statements of Operations was as follows (in thousands):

	Year Ended December 31, 2024	2023	2022
Realized (gain) loss	$ (2,879)	$ 4,087	$ 125,089
Unrealized gain	(710)	(58,846)	(39,556)
Derivative (gain) loss, net	$ (3,589)	$ (54,759)	$ 85,533

Debt

The following table presents the net values and estimated fair values of the Company's debt (in thousands):

	December 31, 2024		December 31, 2023	
	Net Value	Fair Value	Net Value	Fair Value
Term Loan	$ 112,132	$ 109,727	$ 111,107	$ 108,467
11.75% Notes	272,081	278,765	269,910	283,443
TVPX Loan	9,010	9,395	9,587	10,156
Total	$ 393,223	$ 397,887	$ 390,604	$ 402,066

The fair value of the TVPX Loan and the Term Loan were measured using a discounted cash flows model and current market rates. The fair value of the 11.75% Notes was measured using quoted prices, although the market is inactive. The fair value of debt was classified as Level 2 within the valuation hierarchy.

NOTE 12 — INCOME TAXES

Income Tax (Benefit) Expense

Components of income tax (benefit) expense were as follows (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Current	$ 92	$ (140)	$ 8,476
Deferred	(10,077)	18,485	45,184
Total income tax (benefit) expense	$ (9,985)	$ 18,345	$ 53,660

Reconciliation

The Company's income tax (benefit) expense for 2024, 2023 and 2022 resulted in effective tax rates of 10.3%, 54.0% and 18.8%, respectively. The reconciliation of income taxes computed at the U.S. federal statutory tax rate of 21% to these effective tax rates is as follows (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Income tax (benefit) expense at the federal statutory rate	$ (20,397)	$ 7,128	$ 59,810
Compensation adjustments	2,607	1,752	599
State income taxes	(57)	1,143	2,418
Valuation allowance	7,699	8,125	(9,117)
Other	163	197	(50)
Income tax (benefit) expense	$ (9,985)	$ 18,345	$ 53,660

Deferred Tax Assets and Liabilities

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

	December 31, 2024	December 31, 2023
Deferred tax assets:		
Derivatives	$ 4,376	$ 8,532
Asset retirement obligations	118,398	109,111
Contingent asset retirement obligations	4,493	3,952
Right of use liability	2,743	2,895
Federal net operating losses	10,805	6,211
State net operating losses	4,581	5,941
Interest expense limitation carryover	24,947	17,501
Share-based compensation	1,480	2,262
Other	4,560	4,266
Total deferred tax asset	176,383	160,671
Valuation allowance	(29,155)	(23,202)
Total deferred tax asset after valuation allowance	147,228	137,469
Deferred tax liabilities:		
Property and equipment	$ 93,284	$ 92,707
Investment in non-consolidated entity	2,149	2,993
Other	2,995	3,046
Total deferred tax liabilities	98,428	98,746
Net deferred tax asset [1]	$ 48,800	$ 38,723

(1) As of December 31, 2024 and 2023, $8 thousand and $51 thousand are included in *Other liabilities* in the Company's Consolidated Balance Sheets.

Valuation Allowance

Changes to the Company's valuation allowance are as follows (in thousands):

	Year Ended December 31, 2024	2023	2022
Balance at beginning of period	$ (23,202)	$ (15,311)	$ (24,359)
Additions to valuation allowance	(5,953)	(7,891)	—
Reductions to valuation allowance	—	—	9,048
Balance at end of period	$ (29,155)	$ (23,202)	$ (15,311)

Deferred tax assets are recorded related to net operating losses ("NOLs") and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The Company records valuation allowances when it is more likely than not that some portion or all of its deferred tax assets will not be realized. As of each reporting date, the Company assesses available positive and negative evidence regarding its ability to realize its deferred tax assets, including reversing temporary differences and projections of future taxable income during the periods in which those temporary differences become deductible, as well as negative evidence such as historical losses, to evaluate the realizability of its net deferred tax asset position. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or NOLs are deductible.

The amount of the Company's deferred tax assets considered realizable could be adjusted if projections of future taxable income are reduced or objective negative evidence in the form of a three–year cumulative loss is present or both. Should the Company no longer have a level of sustained profitability, it will have to rely more on its future projections of taxable income to determine if the Company has an adequate source of taxable income for the realization of its deferred tax assets, namely NOLs and interest expense limitations.

Net Operating Loss and Interest Expense Limitation Carryover

The table below presents the details of the Company's net operating loss and interest expense limitation carryover as of December 31, 2024 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 51,450	N/A
State net operating loss	104,109	2026 - 2043
Interest expense limitation carryover	115,495	N/A

Uncertain Tax Positions

The Company's tax filings are subject to examination by federal and state tax authorities where it conducts its business. These examinations may result in assessments of additional tax that are resolved with the authorities or through the courts. The Company has evaluated whether any material tax positions it has taken will more likely than not be sustained upon examination by the appropriate taxing authority. As the Company believes that all such material tax positions it has taken are supportable by existing laws and related interpretations, the Company believes there are no material uncertain tax positions to consider.

Years Open to Examination

The Company and its subsidiaries are subject to income taxes in both the U.S. federal jurisdiction and state jurisdictions in which it conducts its business, each of which may have multiple open years subject to examination. As of December 31, 2024, the tax years 2021 through 2024 remain open to examination by the federal and state tax jurisdictions where the Company conducts its business.

NOTE 13 — NET (LOSS) INCOME PER SHARE

The following table presents the calculation of basic and diluted net (loss) income per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2024	2023	2022
Net (loss) income	$ (87,145)	$ 15,598	$ 231,149
Weighted average common shares outstanding - basic	147,133	146,483	143,143
Dilutive effect of securities	—	1,819	1,947
Weighted average common shares outstanding - diluted	147,133	148,302	145,090
Net (loss) income per common share:			
Basic	$ (0.59)	$ 0.11	$ 1.61
Diluted	$ (0.59)	$ 0.11	$ 1.59
Shares excluded due to being anti-dilutive [1]	4,069	—	—

[1] Includes RSUs and the CROCE PSUs as their effect, if included would have been anti-dilutive. The TSR PSUs are not included as they are not likely to attain their applicable performance metric.

NOTE 14 — INVESTMENT IN MONZA

Monza was formed and funded by the Company, third-party investors and an entity owned and controlled by the Company's CEO with total commitments by all members, including the Company's commitment to fund its retained interest in Monza projects held outside of Monza, of $361.4 million, which includes the Company's contribution of 88.94% of its working interest in certain identified undeveloped drilling projects. The entity affiliated with the Company's CEO invested as a minority investor on the same terms and conditions as the third-party investors.

Monza jointly participates with the Company in the exploration, drilling and development of certain drilling projects (the "Joint Venture Drilling Program") in the Gulf of America. The Joint Venture Drilling Program is structured so that the Company initially receives an aggregate of 30.0% of the revenues less expenses, through both the Company's direct ownership of its working interest in the projects and the Company's indirect interest through its interest in Monza, for contributing 20.0% of the estimated total well costs plus associated leases and providing access to available infrastructure at agreed-upon rates. Any exceptions to this structure are approved by the Monza board of directors.

Monza is an entity separate from any other entity with its own separate creditors who will be entitled, upon its liquidation, to be satisfied out of Monza's assets prior to any value in Monza becoming available to holders of its equity. The assets of Monza are not available to pay creditors of the Company and its affiliates.

As of December 31, 2024, nine wells have been completed since the inception of the Joint Venture Drilling Program, of which seven are producing. The Company is the operator for five of these wells completed.

As required, the Company may call on Monza to provide cash to fund its portion of certain Joint Venture Drilling Program projects in advance of capital expenditure spending. As of December 31, 2024 and 2023, the unused advances were $2.4 million and $2.7 million, respectively, which are included in *Accounts payable* in the Consolidated Balance Sheets.

Since inception through December 31, 2024, members of Monza have made partner capital contributions, including the Company's contributions of working interest in the drilling projects, to Monza totaling $302.4 million and received cash distributions totaling $250.4 million. Since inception through December 31, 2024, the Company has made total capital contributions, including the contributions of working interest in the drilling projects, to Monza totaling $68.2 million and received cash distributions totaling $54.0 million.

Consolidation and Carrying Amounts

Monza is considered to be a variable interest entity. As the Company is not considered the primary beneficiary of Monza, the Company does not fully consolidate Monza but instead consolidates Monza based on its ownership interest. The Company reconsiders its evaluation of whether to consolidate Monza each reporting period based upon changes in the facts and circumstances pertaining to Monza. Monza is considered a variable interest entity that is proportionally consolidated. As of December 31, 2024, there have been no events or changes that would cause a redetermination of the variable interest status.

The following table presents the amounts recorded by the Company in the Consolidated Balance Sheets related to the consolidation of the proportional interest in Monza's operations (in thousands):

	December 31,	
	2024	**2023**
Working capital	$ 29	$ 1,159
Oil and natural gas properties and other, net	28,042	31,805
Other assets	13,038	11,694
Asset retirement obligations	691	593

The following table presents the amounts recorded by the Company in the Consolidated Statement of Operations related to the consolidation of the proportional interest in Monza's operations (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Total revenues	$ 11,254	$ 13,086	$ 28,803
Total operating expenses	7,453	9,436	13,523
Interest income	215	199	42

NOTE 15 — SEGMENT INFORMATION

The Company reports its operations in one reportable segment which is engaged in the acquisition, development and production of oil, NGLs and natural gas offshore in the Gulf of America. The segment derives revenue from the sale of produced oil, NGLs and natural gas. The Company's chief operating decision maker ("CODM") is its CEO.

The accounting policies of the Company's operating segment are the same as those described in *Note 1 - Summary of Significant Accounting Policies*. The measure of profit or loss that the CODM uses to assess performance and allocate resources for the operating segment is consolidated net (loss) income. The measure of segment assets is reported on the accompanying consolidated balance sheets as total consolidated assets. The CODM uses consolidated net income in deciding whether to reinvest profits into the operating segment or into other activities, such as for acquisitions or to return capital to shareholders through a combination of dividends and/or share repurchases.

As the Company discloses a single reportable segment, total operating net revenues for the Company's operating segment is reported in its Consolidated Statements of Operations and segment assets is reported in its Consolidated Balance Sheets.

The CODM is regularly provided with only the consolidated expenses as noted on the face of the Consolidated Statements of Operations and, accordingly, these expenses are considered to be significant expenses.

NOTE 16 — OTHER SUPPLEMENTAL INFORMATION

Consolidated Balance Sheet Details

Prepaid expenses and other current assets consisted of the following (in thousands):

	December 31,	
	2024	2023
Derivatives	$ 868	$ 1,180
Insurance/bond premiums	6,988	6,631
Prepaid deposits related to royalties	8,562	7,872
Prepayments to vendors	1,586	1,492
Other	500	272
Prepaid expenses and other current assets	$ 18,504	$ 17,447

Oil and natural gas properties and other, net consisted of the following (in thousands):

	December 31,	
	2024	2023
Oil and natural gas properties and related equipment	$ 9,090,928	$ 8,919,403
Other property	43,589	43,434
Total property and equipment	9,134,517	8,962,837
Less: Accumulated depreciation, depletion, amortization and impairment	(8,356,776)	(8,213,781)
Oil and natural gas properties and other, net	$ 777,741	$ 749,056

Other assets consisted of the following (in thousands):

	December 31,	
	2024	2023
Operating lease right-of-use assets	$ 10,045	$ 10,515
Proportional consolidation of Monza	13,038	11,694
Equity method investments	2,295	2,182
Derivatives	4,150	10,068
Other	1,665	4,464
Total other assets	$ 31,193	$ 38,923

Accrued liabilities consisted of the following (in thousands):

	December 31,	
	2024	2023
Accrued interest	$ 13,472	$ 13,479
Accrued salaries/payroll taxes/benefits	11,623	9,473
Derivatives	3,731	6,267
Operating lease liabilities	1,522	1,455
Contingent P&A liability [1]	1,751	—
Other	1,172	1,304
Total accrued liabilities	$ 33,271	$ 31,978

(2) See *Note 6 — Commitments and Contingencies*.

Consolidated Statement of Cash Flows Information

Supplemental cash flows and noncash transactions were as follows (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Cash and cash equivalents	$ 109,003	$ 173,338	$ 461,357
Restricted cash	1,552	4,417	4,417
Cash, cash equivalents and restricted cash	110,555	177,755	465,774
Supplemental cash flows information:			
Cash paid for interest	40,566	42,132	71,126
Refunds (received) cash paid for income taxes, net	(2,021)	2,392	8,198
Non-cash investing and financing activities:			
Accruals of property and equipment	3,363	7,165	6,636
Dividends declared but not paid on unvested share-based awards	116	—	—
ARO - acquisitions, additions and revisions, net	57,335	37,337	91,652

NOTE 17 — RELATED PARTIES

Related Party Transactions with Affiliates of the CEO

The Company has entered into transactions with related parties either controlled by the Company's CEO or in which he has an ownership interest.

In May 2023, the Company acquired a corporate aircraft from a company affiliated with and controlled by the Company's CEO. The purchase price of the aircraft was $19.1 million, which was paid using $9.0 million of cash on hand and through the assumption of the TVPX Loan (see *Note 5 – Debt*). The terms of this transaction were reviewed and approved by the Audit Committee of the Company's board of directors.

Prior to the Company's purchase of the aircraft, the Company used this aircraft for business purposes, and the CEO also used the aircraft for personal purposes. Both the Company's use of the aircraft for business purposes and the CEO's unlimited use for personal purposes were paid for by the Company pursuant to the CEO's prior employment agreement. Airplane services transactions were approximately $0.2 million and $1.7 million during 2023 and 2022, respectively.

An entity owned by the Company's CEO has ownership interests in certain wells in which the Company does not have an ownership interest. These wells are covered under the Company's insurance policy. The entity reimburses the Company for its proportionate share of insurance premiums related to these wells and, when insurance proceeds are collected related to damage, those costs are disbursed as applicable. In addition, the entity reimburses the Company for certain administrative costs incurred during the year. Reimbursements from such company totaled $0.3 million, $0.4 million and $0.2 million during 2024, 2023 and 2022, respectively, and are included on the Company's Consolidated Statements of Operations as a reduction to general and administrative expenses.

A company that provides marine transportation and logistics services to the Company employs the spouse of the Company's CEO. The rates charged for these marine and transportation services were generally either equal to or below rates charged by non-related, third-party companies and/or otherwise determined to be of the best value to the Company. Payments to such company totaled $20.3 million, $16.5 million and $20.0 million during 2024, 2023 and 2022, respectively. The spouse received commissions partially based on services rendered to the Company which were approximately $0.1 million in each of 2024, 2023 and 2022.

An entity controlled by the Company's CEO purchased $21.0 million in aggregate principal amount of the 11.75% Notes on the same terms as the other purchasers. Subsequent to December 31, 2024, these notes were purchased for cash pursuant to the Tender Offer, and the entity purchased $22.0 million in aggregate principal amount of the 10.75% Senior Second Lien Notes due 2029 (the "10.75% Notes"). See *Note 19 – Subsequent Events* for additional information.

An entity indirectly owned and controlled by the Company's CEO is the sole lender under the Credit Agreement (see *Note 5 – Debt*). In relation to the execution of amendments to the Credit Agreement, the Company paid arrangement and extension fees of approximately $1.1 million during 2022 and paid legal fees on behalf of the entity of approximately $0.1 million during 2022. No arrangement fees or legal fees were paid during 2024 or 2023. In addition, the entity earned commitment fees of $1.5 million in each of 2024, 2023 and 2022, equal to 3.0% of the unused borrowing base lending commitment.

Related Party Transactions for Payments of Services

The Company retains the services of various law firms, including the Hittner Group, where one of the Company's executive officers, George Hittner, was the founder and owner. During 2024, prior to Mr. Hittner's appointment as Executive Vice President, General Counsel and Corporate Secretary of the Company effective September 1, 2024, the Company incurred approximately $1.6 million in fees owed to the Hittner Group related to services performed on behalf of the Company for material litigation and other matters. Since Mr. Hittner's appointment as an executive officer, no additional fees owing to the Hittner Group have been incurred.

NOTE 18 — SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

Capitalized Costs

Net capitalized costs related to oil, NGLs and natural gas producing activities are as follows (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Proved oil and natural gas properties and equipment	$ 9,090,928	$ 8,919,403	$ 8,813,404
Accumulated depreciation, depletion and amortization	(8,331,141)	(8,200,968)	(8,088,271)
Net capitalized costs related to producing activities	$ 759,787	$ 718,435	$ 725,133

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

The following costs were incurred in oil, NGLs and natural gas property acquisition, exploration, and development activities (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Acquisition of proved oil and natural gas properties (1)	$ 98,282	$ 43,736	$ 78,565
Exploration costs (2)	6,758	12,250	24,498
Development costs (3)	71,875	54,022	77,282
Total	$ 176,915	$ 110,008	$ 180,345

(1) Includes capitalized ARO of $17.6 million, $16.4 million and $33.2 million during 2024, 2023 and 2022, respectively.

(2) Includes seismic costs of $1.3 million, $2.8 million, and $5.6 million incurred during 2024, 2023 and 2022, respectively. Includes geological and geophysical costs charged to expense of $5.4million, $4.8 million, and $5.5 million during 2024, 2023 and 2022, respectively.

(3) Includes net additions from capitalized ARO of $39.6 million, $21.0 million and $55.6 million during 2024, 2023 and 2022, respectively. These adjustments for ARO are associated with liabilities incurred and revisions of estimates.

Oil and Natural Gas Reserve Information

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve information represents estimates only and are inherently imprecise. Reserve estimates were prepared based on the interpretation of various data by the Company's independent reservoir engineers, including production data and geological and geophysical data of the Company's existing wells.

All of the Company's reserves are located in the United States with all located in state and federal waters in the Gulf of America. In addition to other criteria, estimated reserves are assessed for economic viability based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for the year in accordance with definitions and guidelines set forth by the SEC. The prices used do not purport, nor should it be interpreted, to present the current market prices related to estimated oil and natural gas reserves.

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Notes to Consolidated Financial Statements (continued)

The following sets forth changes in estimated quantities of net proved oil, NGLs and natural gas reserves:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	MMBoe
Proved reserves as of December 31, 2021	37.2	19.1	607.6	157.6
Revisions of previous estimates	4.5	1.2	64.3	16.3
Purchase of minerals in place	4.5	0.2	7.5	6.0
Production	(5.6)	(1.6)	(44.8)	(14.6)
Proved reserves as of December 31, 2022	40.6	18.9	634.6	165.3
Revisions of previous estimates	—	(4.0)	(168.8)	(32.2)
Purchase of minerals in place	1.4	0.2	5.8	2.6
Production	(5.0)	(1.4)	(37.6)	(12.7)
Proved reserves as of December 31, 2023	37.0	13.7	434.0	123.0
Revisions of previous estimates	7.0	0.2	(77.1)	(5.5)
Purchase of minerals in place	12.9	0.3	51.8	21.7
Production	(5.3)	(1.2)	(34.3)	(12.2)
Proved reserves as of December 31, 2024	51.6	13.0	374.4	127.0
Year-end proved developed reserves:				
2024	37.0	12.2	336.0	105.3
2023	27.4	12.7	379.4	103.3
2022	31.1	17.6	576.0	144.8
Year-end proved undeveloped reserves:				
2024	14.6	0.8	38.4	21.7
2023	9.6	1.0	54.6	19.7
2022	9.5	1.3	58.6	20.5

During 2024, increases in revisions of previous estimates were primarily related to upward revisions to the Garden Banks 783 field offset by decreases due to SEC price revisions for all proved reserves. Proved reserves were also added through the acquisition of properties in January 2024.

During 2023, decreases in revisions of previous estimates were primarily due to SEC price revisions for all proved reserves. Proved reserves were also added through the acquisition of properties in September 2023.

During 2022, increases in revisions of previous estimates were primarily due to upward revisions to the Brazos A133 field combined with increases due to SEC price revisions for all proved reserves. Proved reserves were also added through the acquisitions of properties acquired from ANKOR and subsequent working interest acquisition in the same properties from a private seller.

As of December 31, 2024, we believe that we will be able to develop all but 5.9 MMBoe (approximately 27%) of the total 21.7 MMBoe classified as PUDs within five years from the date such PUDs were initially recorded. The primary exceptions are at the Mississippi Canyon 243 field ("Matterhorn"), Ship Shoal 349 field ("Mahogany") and Viosca Knoll 823 field ("Virgo") where future development drilling has been planned as sidetracks of existing wellbores due to conductor slot limitations and rig availability. Three sidetrack PUD locations, one each at Matterhorn, Mahogany and Virgo, will be delayed until an existing well is depleted and available to sidetrack. Based on the latest reserve report, these PUD locations are expected to be developed in 2026 and 2036. The other exception is at the Garden Banks 783 field ("Magnolia") where significant spending has already begun on rig and platform modifications for development drilling, but the timeline has been extended to 2026 before we will be able to mobilize the rig.

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to the Company's proved oil, NGLs and natural gas reserves together with changes therein (in millions):

	Year Ended December 31,		
	2024	2023	2022
Future cash inflows	$ 5,123.1	$ 4,282.3	$ 8,856.0
Future costs:			
Production	(2,361.9)	(2,007.6)	(2,895.0)
Development and abandonment	(1,645.0)	(1,052.3)	(990.0)
Income taxes	(215.9)	(210.3)	(1,006.0)
Future net cash inflows	900.3	1,012.1	3,965.0
10% annual discount factor	(160.2)	(328.9)	(1,702.0)
Standardized measure of discounted future net cash flows	$ 740.1	$ 683.2	$ 2,263.0

Future cash inflows represent expected revenues from production of period-end quantities of proved reserve computed using SEC pricing for the periods presented. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials. Due to the lack of a benchmark price for NGLs, a ratio is computed for each field of the NGLs realized price compared to the WTI oil spot price. Then, this ratio is applied to the oil price using SEC guidance. The average realized commodity prices used to determine the standardized measure are as follows:

	December 31,		
	2024	2023	2022
Oil ($/Bbl)	$ 74.69	$ 74.79	$ 91.50
NGLs ($/Bbl)	22.98	24.08	41.92
Natural gas ($/Mcf)	2.58	2.74	6.85

Future production, development and abandonment costs and production rates and timing were based on the best information available to the Company. Estimated future net cash flows, net of future income taxes, have been discounted to their present values based on the prescribed annual discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of the Company's oil, NGLs and natural gas reserves. Actual prices realized, costs incurred, and production quantities and timing may vary significantly from those used.

The change in the standardized measure of discounted future net cash flows relating to the Company's proved oil, NGLs and natural gas reserves is as follows (in millions):

	Year Ended December 31,		
	2024	2023	2022
Standardized measure, beginning of year	$ 683.2	$ 2,263.0	$ 1,156.0
Sales and transfers of oil, NGL and natural gas produced, net of production costs	(205.1)	(240.1)	(672.7)
Net changes in prices and production costs	38.6	(1,241.4)	1,368.6
Net change in future development costs	(102.1)	(22.0)	(15.2)
Revisions of quantity estimates	(16.7)	(828.8)	249.1
Acquisition of reserves in place	245.9	72.0	225.2
Accretion of discount	79.2	285.7	138.1
Net change in income taxes	(45.6)	443.1	(369.3)
Changes in timing and other	62.7	(48.3)	183.2
Standardized measure, end of year	$ 740.1	$ 683.2	$ 2,263.0

NOTE 19 — SUBSEQUENT EVENTS (UNAUDITED)

In December 2024, the Company entered into a purchase and sale agreement to sell a non-core interest in the Garden Banks Blocks 385 and 386. The effective date of the sale was December 1, 2024, and the transaction closed on January 8, 2025 for approximately $11.9 million following customary purchase price adjustments.

In January 2025, the Company received $58.5 million related to the settlement of claims related to the Mobile Bay plant turnaround in February 2023. During the turnaround, the MB 78-1 well was shut-in and did not return to production following completion of the planned maintenance. The Company filed a claim under its Energy Package Policy and in December 2024, the Company and the underwriters of the Energy Package Policy agreed to a settlement of claims.

On January 28, 2025, the Company issued and sold $350.0 million in aggregate principal amounts of its 10.75% Notes, which are governed under an indenture dated January 28, 2025 (the “2025 Indenture”). The 10.75% Notes mature on February 1, 2029 and interest is payable on each February 1 and August 1, commencing August 1, 2025. The 10.75% Notes are guaranteed by the Company’s direct and indirect wholly-owned subsidiaries (the “Guarantors”). The 10.75% Notes are secured by second priority liens (subject to permitted liens and certain other exceptions) on substantially all of the oil and natural gas properties of the Company and the Guarantors.

Prior to February 1, 2027, the Company may redeem all or any portion of the 10.75% Notes at a redemption price equal to 100% of the principal amount of the outstanding 10.75% Notes plus accrued and unpaid interest to the redemption date plus the applicable premium (as defined in the 2025 Indenture). In addition, prior to February 1, 2027, the Company may, at its option, on one or more occasions, redeem up to 35% of the aggregate original principal amount of the 10.75% Notes in an amount not greater than the net cash proceeds from certain equity offerings at a redemption price of 110.75% of the principal amount of the outstanding 10.75% Notes plus accrued and unpaid interest to the redemption date. From February 1, 2027 to (and including) January 31, 2028, the Company may redeem the 10.75% Notes in whole or in part, at redemption prices (expressed as percentages of the principal amount thereof) equal to 105.375% and 100.000% from February 1, 2028 and thereafter, plus accrued and unpaid interest, if any, to the redemption date.

An entity controlled by the Company’s CEO purchased $22.0 million in aggregate principal amount of the 10.75% Notes on the same terms as the other purchasers.

The net proceeds from the issuance of the 10.75% Notes along with cash on hand were used to (i) purchase for cash pursuant to the Tender Offer, such of the Company’s outstanding 11.75% Notes that were validly tendered (and not validly withdrawn) pursuant to the terms of the Tender Offer, (ii) on or after August 1, 2025, redeem in full any remaining 11.75% Notes not validly tendered and accepted for purchase in the Tender Offer and, pending such redemptions, satisfy and discharge the Indenture, (iii) repay outstanding amounts under the Term Loan, and (iv) pay premiums, fees and expenses relating to these transactions. As a result, the Company and the guarantors of the 11.750% Notes have been released from their remaining obligations under the Indenture.

On January 28, 2025, the Company terminated the Credit Agreement and entered into a new credit agreement (the “New Credit Agreement”) which provides the Company a revolving credit and letter of credit facility with initial bank lending commitments of $50.0 million with a letter of credit sublimit of $10.0 million. The New Credit Agreement matures on July 28, 2028.

The New Credit Agreement is guaranteed by the Guarantors and is secured by a first priority lien on substantially all the oil and natural gas properties and personal property assets of the Company and the Guarantors. Borrowings under the New Credit Agreement bear interest, at the Company’s option, at a rate per annum equal to either the adjusted Term SOFR rate (the “Adjusted Term SOFR”) plus the applicable margin or the base rate (the “Base Rate”) plus the applicable margin (all terms as defined in the New Credit Agreement). Interest is payable quarterly in arrears for Base Rate loans, at the end of the applicable interest period for Adjusted Term SOFR loans (but not less frequently than quarterly) and upon the prepayment or maturity of the underlying loans. Additionally, the Company is required to pay a letter of credit fee (as defined in the New Credit Agreement), a commitment fee (as defined in the New Credit Agreement) quarterly in arrears in respect of unused commitments under the New Credit Agreement and an annual administrative fee in the amount of $45,000 to be paid quarterly.

On March 3, 2025, the board of directors approved a first quarter dividend of $0.01 per share. The Company expects to pay the dividend on March 24, 2025, to stockholders of record as of the close of business on March 17, 2025.

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

In accordance with Exchange Act Rules 13a-15 and 15d-15, our management, with the participation of our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer, supervised and participated in our evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2024. 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 our principal executive officer and principal financial officer, 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. However, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Consequently, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2024 at the reasonable assurance level.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Management conducted an evaluation and assessment of the effectiveness of our internal control over financial reporting as of December 31, 2024, based on the criteria set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on this assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2024.

The effectiveness of our internal control over financial reporting as of December 31, 2024 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Attestation Report of the Registered Public Accounting Firm

Deloitte & Touche LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2024, which is included under Part II, Item 8. *Financial Statements and Supplementary Data*, in this Form 10-K.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2024, none of our directors or "officers" (as such term is defined in Rule 16(a)-1(f) under the Exchange Act) adopted or terminated a "Rule 10b5-1 trading agreement" or "non-Rule 10b5-1 trading arrangement" (each as defined in Item 408(a) and (c) of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Our board of directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors and employees, which is available on our website (*www.wtoffshore.com*) under “Investors.” We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on the website address and location specified above.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as a part of this Form 10-K:

1. Financial Statements

See "Index to Consolidated Financial Statements" in Part II, Item 8 of this Form 10-K.

2. Financial Statement Schedules

All schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

3. Exhibits

Exhibit Number	Description
3.1	Second Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q, filed August 2, 2023)
3.2	Fourth Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed April 26, 2023)
4.1†	Indenture, dated as of January 27, 2023, by and among W&T Offshore, Inc., the guarantors party thereto and Wilmington Trust, National Association, as trustee (including form of 11.75% Senior Second Lien Notes due 2026) (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on January 30, 2023)
4.2	Form of 11.750% Senior Second Lien Note due 2026 (included in Exhibit 4.1 hereto)
4.3	First Supplemental Indenture, dated as of May 25, 2023, among Falcon Aero Holdings LLC, Falcon Aero Holdco LLC, W&T Offshore, Inc., the other Guarantors party thereto and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q, filed August 2, 2023)
4.4*	Second Supplemental Indenture, dated as of January 27, 2025, among W&T Offshore, Inc., the other Guarantors party thereto and Wilmington Trust, National Association, as trustee
4.5†	Indenture, dated as of January 28, 2025, by and among W&T Offshore, Inc., the guarantors party thereto and Wilmington Trust, National Association, as trustee (including form of 10.750% Senior Second Lien Notes due 2029) (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on February 3, 2025)
4.6	Form of 10.750% Senior Second Lien Notes due 2029 (included in Exhibit 4.5 hereto)
4.7	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended (Incorporated by reference to Exhibit 4.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2019)
10.1+	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1, filed May 3, 2004)

10.2+	First Amendment to the 2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Appendix A of the Company's Definitive Proxy Statement, filed March 26, 2020)
10.3+	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010)
10.4+	First Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013)
10.5+	Second Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013)
10.6+	Third Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2016)
10.7+	Fourth Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2017)
10.8+	Employment Agreement between W&T Offshore, Inc. and Tracy W. Krohn dated as of November 1, 2010 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on November 5, 2010)
10.9+	Amended and Restated Employment Agreement between W&T Offshore, Inc. and Tracy W. Krohn (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on April 26, 2023)
10.10+	Form of Indemnification Agreement by and between W&T Offshore, Inc. and each of its directors and certain of its officers (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q, filed August 8, 2022)
10.11	Intercreditor Agreement, dated May 11, 2015, by and among W&T Offshore, Inc. Toronto Dominion (Texas) LLC, as priority lien agent, Morgan Stanley Senior Funding, Inc. as second lien collateral trustee, and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed May 14, 2015)
10.12	First Amendment to Intercreditor Agreement, dated as of October 18, 2018, by and among Toronto Dominion (Texas) LLC, as Original Priority Lien Agent, Morgan Stanley Senior Funding, Inc., as Original Second Lien Collateral Trustee, Wilmington Trust, National Association, as Original Second Lien Trustee, Wilmington Trust, National Association, as Second Lien Trustee, Wilmington Trust, National Association, as Second Lien Collateral Trustee, Cortland Capital Market Services LLC, as Priority Lien Agent, Wilmington Trust, National Association as Third Lien Collateral Trustee and Wilmington Trust, National Association as Third Lien Trustee (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on October 24, 2018)

10.13	Priority Confirmation Joinder, dated as of January 27, 2023, to the Intercreditor Agreement, as amended, by and between Alter Domus (US) LLC, as Priority Lien Agent for the Priority Lien Secured Parties and Wilmington Trust, National Association, as Second Lien Collateral Trustee for the Second Lien Secured Parties (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on January 30, 2023)
10.14	Sixth Amended and Restated Credit Agreement, dated as of October 18, 2018, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed on October 24, 2018)
10.15	First Amendment to Sixth Amended and Restated Credit Agreement, dated November 27, 2019, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2019, filed on March 5, 2020)
10.16	Second Amendment and Consent to Sixth Amended and Restated Credit Agreement, dated February 24, 2020, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.15 of the Company's Annual Report on Form 10-K for the year ended December 31, 2019, filed on March 5, 2020)
10.17	Third Amendment and Waiver to Sixth Amended and Restated Credit Agreement, dated June 17, 2020, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly report on Form 10-Q, filed on June 23, 2020)
10.18	Fourth Amendment to Sixth Amended and Restated Credit Agreement, dated July 24, 2020, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto (Incorporated by reference to exhibit 10.19 of the Company's Current Annual Report on Form 10-K for the year ended December 31, 2020, filed on March 4, 2021)
10.19	Waiver, Consent to Second Amendment to Intercreditor Agreement and Fifth Amendment to Sixth Amended and Restated Credit Agreement, dated January 6, 2021, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto (Incorporated by reference to exhibit 10.1 of the Company's Current Report on Form 8-K, filed on January 12, 2021)
10.20	Waiver, Consent and Sixth Amendment to Sixth Amended and Restated Credit Agreement, dated May 19, 2021, by and among W&T Offshore, Inc., the guarantor subsidiaries party thereto, the lenders party thereto, the issuers of letters of credit party thereto and Toronto Dominion (Texas) LLC, individually and as agent (Incorporated by reference to exhibit 10.1 of the Company's Current Report on Form 8-K, filed on May 25, 2021)
10.21	Waiver and Seventh Amendment to Sixth Amended and Restated Credit Agreement, dated June 30, 2021 by and among W&T Offshore, Inc., the guarantor subsidiaries party thereto, the lenders party thereto, the issuers of letters of credit party thereto and Toronto Dominion (Texas) LLC, individually and as agent (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q, filed on August 4, 2021)
10.22	Eighth Amendment to the Sixth Amended and Restated Credit Agreement and Master Assignment, Registration and Appointment Agreement, dated effective as of November 2, 2021 (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed on November 3, 2021)

10.23	Ninth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of November 2, 2021 (Incorporated by reference Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q, filed on November 3, 2021)
10.24	Tenth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of March 8, 2022 (Incorporated by reference Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed on May 4, 2022)
10.25	Eleventh Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of November 8, 2022 (Incorporated by reference Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed on November 9, 2022)
10.26†	Twelfth Amendment to the Sixth Amended and Restated Credit Agreement dated as of May 15, 2023 (Incorporated by reference Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on May 19, 2023)
10.27	Thirteenth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of December 29, 2023 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 2, 2024)
10.28	Fourteenth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of January 26, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 26, 2024)
10.29	Fifteenth Amendment to the Sixth Amended and Restated Credit Agreement dated as of February 28, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed March 1, 2024)
10.30	Sixteenth Amendment to the Sixth Amended and Restated Credit Agreement dated as of March 28, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed March 28, 2024)
10.31	Seventeenth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of April 29, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 1, 2024)
10.32	Third Waiver to Sixth Amended and Restated Credit Agreement, dated as of January 17, 2024 (Incorporated by reference to Exhibit 10.7 of the Company's Quarterly Report on Form 10-Q, filed on May 10, 2024)
10.33	Eighteenth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of May 29, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 30, 2024)
10.34	Nineteenth Amendment to the Sixth Amended and Restated Credit Agreement dated effective as of June 28, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 1, 2024)
10.35	Twentieth Amendment to the Sixth Amended and Restated Credit Agreement, dated as of December 27, 2024 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 2, 2025)

10.36	Credit Agreement, dated May 19, 2021, by and among Aquasition LLC, as Borrower, Aquasition II LLC, as Co-Borrower, and Munich Re Reserve Risk Financing, as the lenders party thereto (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q, filed on August 8, 2021)
10.37	First Amendment to Credit Agreement, dated as of March 17, 2024, by and among Aquasition LLC, as Borrower, Aquasition II LLC, as Co-Borrower, and Munich Re Reserve Risk Financing, as the lender party thereto (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed March 18, 2024)
10.38†	Credit Agreement, dated as of January 28, 2025, by and among W&T Offshore, Inc., Texas Capital Bank, as agent and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed February 3, 2025)
10.39	Intercreditor Agreement, dated as of January 28, 2025, by and between Wilmington Trust, National Association, as second lien collateral trustee and Texas Capital Bank, as priority lien agent (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed February 3, 2025)
10.40	Purchase and Sale Agreement, dated December 13, 2023, by and among W&T Offshore, Inc., as buyer, and Cox Oil Offshore, L.L.C., Energy XXI GOM, LLC, EPL Oil & Gas, LLC, MLCJR LLC, Cox Operating L.L.C., Energy XXI Gulf Coast, LLC and M21K, LLC, as sellers (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed December 15, 2023)
10.41†	First Amendment to Purchase and Sale Agreement, dated as of January 12, 2024, by and among Cox Oil Offshore, L.L.C., a Louisiana limited liability company, Energy XXI GOM, LLC, a Delaware limited liability company, EPL Oil & Gas, LLC, a Delaware limited liability company, MLCJR LLC, a Texas limited liability company, Cox Operating L.L.C., a Louisiana limited liability company, Energy XXI Gulf Coast, LLC, a Delaware limited liability company, M21K, LLC, a Delaware limited liability company, and W&T Offshore, Inc., a Texas corporation (Incorporated by reference to Exhibit 10.8 of the Company's Quarterly Report on Form 10-Q, filed on May 10, 2024)
10.42	Management Services Agreement, dated May 19, 2021, by and among Aquasition LLC, Aquasition II LLC, and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q, filed on August 8, 2021)
10.43+	W&T Offshore, Inc. 2023 Incentive Compensation Plan (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed June 20, 2023)
10.44+	W&T Offshore, Inc. Change in Control Severance Plan (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed June 20, 2023)
10.45+	Form of Restricted Stock Unit Agreement (Service-based Vesting), pursuant to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed August 8, 2022)
10.46+	Form of Restricted Stock Unit Agreement (Performance Vesting), pursuant to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed August 8, 2022)
10.47+	Form of Restricted Stock Unit Agreement (Service-based Vesting), pursuant to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q, filed August 2, 2023)

10.48+	Form of Restricted Stock Unit Agreement (Performance Vesting), pursuant to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q, filed August 2, 2023)
10.49+	Form of Restricted Stock Unit Grant Notice (Performance Vesting), pursuant to the W&T Offshore, Inc. 2023 Incentive Compensation Plan (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q, filed November 8, 2023)
10.50+	Form of Restricted Stock Unit Grant Notice (Service-based Vesting), pursuant to the W&T Offshore, Inc. 2023 Incentive Compensation Plan (Incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q, filed November 8, 2023)
10.51+	Form of Non-Employee Director Restricted Stock Unit Grant Notice, pursuant to the W&T Offshore, Inc. 2023 Incentive Compensation Plan (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed November 8, 2023)
10.52+	Form of 2023 Executive Annual Incentive Award Agreement (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed August 2, 2023)
19.1*	Insider Trading Policy
21.1*	Subsidiaries of the Registrant
22.1*	List of Issuers and Guarantor Subsidiaries
23.1*	Consent of Deloitte & Touche LLP, Independent Registered Public Accounting Firm
23.2*	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm
23.3*	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350
97.1	W&T Offshore, Inc. Clawback Policy, dated December 1, 2023 (Incorporated by reference to exhibit 97.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2023, filed on March 6, 2024)
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists
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 Label Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
104*	Cover Page Interactive Data File (formatted as Inline XBLE and contained in Exhibit 101)

+ Management Contract or Compensatory Plan or Arrangement.
* Filed herewith.
** Furnished herewith.
† Certain schedules and similar attachments to this agreement have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The Company hereby undertakes to furnish a supplemental copy to each some omitted schedule or similar attachment 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 Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, on March 4, 2025.

W&T OFFSHORE, INC.
By: /S/ SAMEER PARASNIS
Sameer Parasnis
Executive Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 4, 2025.

/S/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)
/S/ SAMEER PARASNIS **Sameer Parasnis**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ BART P. HARTMAN III **Bart P. Hartman III**	Vice President and Chief Accounting Officer (Principal Accounting Officer)
/S/ VIRGINIA BOULET **Virginia Boulet**	Director
/S/ JOHN D. BUCHANAN **John D. Buchanan**	Director
/S/ DR. NANCY CHANG **Dr. Nancy Chang**	Director
/S/ DANIEL O. CONWILL IV **Daniel O. Conwill IV**	Director
/S/ B. FRANK STANLEY **B. Frank Stanley**	Director

Exhibit 4.4

W&T OFFSHORE, INC.,
as the Issuer,

the Guarantors party hereto
and

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Trustee

SECOND SUPPLEMENTAL INDENTURE

Dated as of January 27, 2025

11.750% Senior Second Lien Notes due 2026

THIS SECOND SUPPLEMENTAL INDENTURE dated as of January 27, 2025 (this "Second Supplemental Indenture") among W&T Offshore, Inc., a Texas corporation (the "Company"), the guarantors listed on the signature page hereto (the "Guarantors" and each a "Guarantor") and Wilmington Trust, National Association, as trustee (the "Trustee") under that certain Indenture, by and among the Company, the Guarantors party thereto and the Trustee, dated as of January 27, 2023 (the "Base Indenture"), as supplemented by the Supplemental Indenture, dated as of May 25, 2023, by and among the Company, the Guarantors party thereto and the Trustee (the "First Supplemental Indenture" and together with the Base Indenture, the "Indenture"). Capitalized terms used herein and not otherwise defined shall have the meanings assigned to them in the Indenture.

W I T N E S S E T H

WHEREAS, the Company, has issued its 11.750% Senior Second Lien Notes due 2026 (the "Notes") pursuant to the Indenture;

WHEREAS, the Company has issued its new 10.750% Senior Second Lien Notes due 2029 (the "New Notes"), with a portion of the proceeds therefrom intended to be used by the Company to consummate the Tender Offer (as hereinafter defined);

WHEREAS, $275,000,000 aggregate principal amount of the Notes is currently outstanding;

WHEREAS, the Company is conducting a tender offer (the "Tender Offer") pursuant to which it has offered to purchase for cash any and all outstanding Notes pursuant to the Company's Offer to Purchase and Consent Solicitation Statement dated January 13, 2025 (the "Offer to Purchase");

WHEREAS, in connection with the Tender Offer, the Company has requested that Holders of the Notes deliver their consents with respect to the deletion of certain provisions of the Indenture;

WHEREAS, Section 9.02 of the Indenture provides that, subject to certain exceptions inapplicable hereto, the Company, the Guarantors and the Trustee may amend or supplement the Indenture, the Notes and the Notes Guarantees with the consent of the Holders of at least a majority in aggregate principal amount of the then outstanding Notes voting as a single class (including, without limitation, consents obtained in connection with a tender offer for the Notes);

WHEREAS, the Company's Board of Directors has approved the Company's execution of this Second Supplemental Indenture;

WHEREAS, the Holders of a majority in aggregate principal amount of the Notes outstanding have duly consented, and not duly revoked such consents, to the proposed modifications set forth in this Second Supplemental Indenture in accordance with Section 9.02 of the Indenture;

WHEREAS, the Company has heretofore delivered or is delivering contemporaneously herewith to the Trustee (i) one or more board resolutions authorizing the execution of this Second Supplemental Indenture, (ii) evidence of the written consent of the Holders set forth in the immediately preceding paragraph and (iii) the Officers' Certificate and the Opinion of Counsel described in Sections 7.02 and 9.05 of the Indenture; and

WHEREAS, all conditions necessary to authorize the execution and delivery of this Second Supplemental Indenture and to make this Second Supplemental Indenture valid and binding have been complied with or have been done or performed.

NOW, THEREFORE, in consideration of the foregoing and notwithstanding any provision of the Indenture which, absent this Second Supplemental Indenture, might operate to limit such action, the parties hereto, intending to be legally bound hereby, agree as follows:

ARTICLE I

AMENDMENT OF INDENTURE

Section 1.1 Amendments.

(a) Subject to Section 2.1 hereof, the Indenture is hereby amended by deleting in their entireties Section 4.03, other than clause (g) thereof; Section 4.07; Section 4.08; Section 4.09; Section 4.10; Section 4.11; Section 4.12; Section 4.13; Section 4.14; Section 4.16; Sections 5.01(1), (3), (4) and (5); and Sections 6.01(3), (4), (5), (6) and (9) with respect to events of default specified in such subsections.

Section 1.2 Amendments to Definitions and Section References.

(a) Subject to Section 2.1 hereof, the Indenture is hereby amended by deleting any definitions from the Indenture with respect to which references have been eliminated as a result of the amendments to the Indenture pursuant to Section 1.1 hereof.

(b) Subject to Section 2.1 hereof, the Indenture is hereby amended by deleting therefrom any references to sections of the Indenture which have been deleted as a result of the amendments to the Indenture pursuant to Section 1.1 hereof.

ARTICLE II

MISCELLANEOUS PROVISIONS

Section 2.1 Effect of Second Supplemental Indenture.

Except as amended hereby, all of the terms of the Indenture shall remain and continue in full force and effect and are hereby confirmed in all respects. From and after the date of this Second Supplemental Indenture, all references to the Indenture (whether in the Indenture or in any other agreements, documents or instruments) shall be deemed to be references to the Indenture as amended and supplemented by this Second Supplemental Indenture. This Second Supplemental Indenture (including the amendments to the Indenture set forth in Article I hereof) shall be effective as of the date first written above; *provided*, *however*, that the amendments to the Indenture set forth in Article I hereof shall not become operative, unless and until (i) Notes representing at least a majority in aggregate principal amount of the Notes outstanding and that were validly tendered (and not validly withdrawn) are accepted for purchase in the Tender Offer and (ii) the Total Consideration for such Notes, plus Accrued Interest thereon (each as defined in the Offer to Purchase) is delivered pursuant to the Tender Offer on the Early Settlement Date (as defined in the Offer to Purchase). Upon satisfaction of the conditions set forth in the immediately preceding sentence, such amendments shall become operative automatically, and promptly thereafter the Company shall notify the Trustee in writing (which may be by email) that the amendments to the Indenture set forth in Article I hereof have become operative on such Early Settlement Date.

Section 2.2 Governing Law.

THE LAWS OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SECOND SUPPLEMENTAL INDENTURE.

Section 2.3 No Representations by Trustee.

The recitals contained herein shall be taken as the statements of the Company only, and the Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein.

Section 2.4 Counterparts.

This Second Supplemental Indenture may be executed in any number of counterparts, each of which shall be an original; but such counterparts shall constitute but one and the same instrument.

(*Signature Pages Follow*)

IN WITNESS WHEREOF, the parties hereto have caused this Second Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

W&T OFFSHORE, INC.

By: /s/ Sameer Parasnis
Name: Sameer Parasnis
Title: Executive Vice President and Chief Financial Officer

GUARANTORS:

AQUASITION III LLC
AQUASITION IV LLC
AQUASITION V LLC
FALCON AERO HOLDCO LLC
FALCON AERO HOLDINGS LLC
GREEN HELL LLC
SEAQUESTER LLC
SEAQUESTRATION LLC
W & T ENERGY VI, LLC
W & T ENERGY VII, LLC

By: /s/ Sameer Parasnis
Name: Sameer Parasnis
Title: Executive Vice President and Chief Financial Officer

(Signature Page to Second Supplemental Indenture)

TRUSTEE:

WILMINGTON TRUST, NATIONAL ASSOCIATION, as Trustee

By: /s/ Quinton M. DePompolo
Name: Quinton M. DePompolo
Title: Assistant Vice President

(Signature Page to Second Supplemental Indenture)

Exhibit 19.1

W&T OFFSHORE, INC.

INSIDER TRADING POLICY

1. Introduction

The Board has adopted this insider trading policy (this "Policy") to provide guidelines to all directors, officers and employees of the Company with respect to trading in the Company's securities, as well as the securities of other publicly traded companies. This policy has been designed to prevent insider trading or even allegations of insider trading. Your strict adherence to this policy will help safeguard the Company's reputation and will further ensure that the Company conducts its business in accordance with the Code of Business Conduct and Ethics. Federal and state securities laws prohibit the purchase or sale of a company's securities by anyone who is aware of material information about that company that is not generally known or available to the public. These laws also prohibit anyone who is aware of material nonpublic information from disclosing this information to others who may trade in securities. Companies and their controlling persons may also be subject to liability if they fail to take reasonable steps to prevent insider trading by company personnel.

It is important that you understand the breadth of activities that constitute illegal insider trading and the consequences, which can be severe. Cases have been successfully prosecuted against trading by associates through foreign accounts, trading by family members and friends, and trading involving only a small number of shares. Both the SEC and the Financial Industry Regulatory Authority investigate and are very effective at detecting insider trading. Both the SEC and the U.S. Department of Justice pursue insider trading violations vigorously. The penalties for violating insider trading laws include imprisonment, disgorgement of profits, civil fines, and criminal fines of up to $5 million for individuals and $25 million for corporations. Insider trading is also prohibited by this Policy, and violation of this Policy may result in Company-imposed sanctions, including removal, dismissal for cause and potential clawback of equity compensation.

2. General Policy

- Directors, officers and employees (an "insider") who are aware of material nonpublic information (described further below) from or about the Company are not permitted to, directly or indirectly or through family members or other persons or entities, to:

- Buy or sell any securities, including, but not limited to, equity, debt, preferred or convertible securities (or derivatives relating to such securities) of the Company and including any transfers in or out of the Company stock funds in any savings plan the Company may have or changes in patterns involving purchases of the Company's securities within the plans (other than pursuant to a 10b5-1 Plan (as defined below)); or

- Pass on, tip or disclose material, non-public information to others outside the Company, including family and friends.

The same policy also applies to securities issued by another company if a director, officer or employee has acquired material, nonpublic information relating to such company in the course of his or her employment or affiliation with the Company.

When material information has been publicly disclosed, each director, officer and employee must continue to refrain from buying or selling the securities in question until the beginning of the third business day after the information has been publicly released to allow the markets to absorb the information.

3. Material Information

Information is generally considered "Material" if there is a likelihood that a reasonable investor would consider it important in making a decision to buy, sell or hold a security, or if the information is likely to have a significant effect on the market price of the security. Material information can be positive or negative and can relate to virtually any aspect of a company's business or to any type of security, debt or equity. There is no bright-line standard for assessing materiality; rather, materiality is based on an assessment of all of the facts and circumstances, and is often evaluated by enforcement authorities with the benefit of hindsight. Examples of information that could be considered material information in some circumstances include:

- Financial results, including earnings and revenue information, a change in earnings or earnings projections, or unexpected or unusual gains or losses in major operations.
- Negotiations and agreements regarding mergers, concessions, joint ventures, acquisitions, divestitures, business combinations or tender offers.
- An increase or decrease in dividends on the Company's common stock or the declaration of a stock split or the proposed or contemplated issuance, redemption, or repurchase of securities.
- Extraordinary borrowing or liquidity problems.
- Defaults under agreements or actions by creditors, clients, or suppliers relating to a company's credit rating.
- Major regulatory changes that will affect the Company particularly.
- Changes in directors, senior management or auditors.
- Changes in control.
- Information as to results of significant exploration and production activity.
- Major environmental incidents.
- Significant actual or potential cybersecurity incidents, events or risks that affect the

Company or third-party providers that support the Company's business operations, including computer system or network compromises, viruses or other destructive software, and data breach incidents that may disclose personal, business or other confidential information.

- A substantial contract award or termination.
- A major lawsuit, claim, investigation or regulatory action or proceeding.
- The gain or loss of, or a significant change in a relationship with, a significant customer or supplier.
- Bankruptcy or liquidity concerns or developments.
- Information that is considered confidential.
- Any other information that could affect the Company's stock price.

4. Public Disclosure

Information is "non-public" if it is not generally known or available to the general public. In order for information to be considered public, it must be widely disseminated in a manner making it generally available to investors through such media as Dow Jones, Business Wire, Reuters, The Wall Street Journal, Associated Press, or United Press International, a broadcast on widely available radio or television programs, publication in a widely available newspaper, magazine or news web site, a Regulation FD-compliant conference call, or public disclosure documents filed with the SEC that are available on the SEC's web site.

The circulation of rumors, even if accurate and reported in the media, does not constitute effective public dissemination. In addition, even after a public announcement, a reasonable period of time must lapse in order for the market to react to the information. Generally, the beginning of the third full trading day following publication is reasonable time after which such information can be deemed to be public.

5. Additional Prohibited Transactions

a. Short Sales

Short sales of the Company's securities evidence an expectation on the part of the seller that the securities will decline in value, and therefore signal to the market that the seller has no confidence in the Company or its short-term prospects. In addition, short sales may reduce the seller's incentive to improve the Company's performance. For these reasons, short sales of the Company's securities are prohibited by this Policy.

b. Publicly Traded Options

A transaction in options is, in effect, a bet on the short-term movement of the Company's stock and therefore creates the appearance that an officer, director or employee is trading based on insider information. Transactions in options also may focus an officer's, director's or employee's attention on short-term performance at the expense of the Company's long-term objectives. Accordingly, transactions in puts, calls or other derivative securities involving the Company's equity securities, on an exchange or in any other organized market, are prohibited by this Policy.

c. Hedging Transactions

Certain forms of hedging or monetization transactions, such as zero-cost collars and forward sale contracts, allow an officer, director or employee to lock in much of the value of his or her stock holdings, often in exchange for all or part of the potential for upside appreciation in the stock. These transactions allow the officer, director or employee to continue to own the covered securities, but without the full risks and rewards of ownership. When that occurs, the officer, director or employee may no longer have the same objectives as the Company's other stockholders. Therefore, all hedging transactions involving the Company's equity securities are prohibited by this Policy.

d. Purchases on Margin

Purchasing on margin means borrowing from a brokerage firm, bank or other entity in order to purchase the Company's securities (other than in connection with a cashless exercise of stock options through a broker under the Company's equity plans). Margin purchases of the Company's securities are prohibited by this Policy. Pledging the Company's securities as collateral to secure loans is prohibited. This prohibition means, among other things, that you cannot hold the Company's securities in a "margin account" (which would allow you to borrow against your holdings to buy securities).

6. When and How to Trade Company Securities

a. Trading Pre-Clearance for Certain Restricted Persons

Certain persons designated and so notified by the General Counsel ("Restricted Persons"), in consultation with the Chief Executive Officer and the Chief Financial Officer from time to time, must obtain pre-clearance by the General Counsel or, in his or her absence, the Chief Financial Officer (each an "Approving Person") before engaging in any transaction involving the Company's securities, including, but not limited to, purchases, sales, and gifts, other than transactions pursuant to pre-cleared 10b5-1 Plans (as defined below). Those Restricted Persons who are required to obtain pre-clearance will be notified from time to time by the General Counsel of the applicable pre-clearance or other procedures applicable to them. Each Approving Person should consult with the other Approving Person, or his or her designee, prior to granting pre-clearance for trades. No Approving Person may engage in a transaction in the Company's securities unless another Approving Person has pre-cleared the transaction.

All requests must be submitted to the applicable Approving Person at least two business days in advance of the proposed transaction. The Approving Person will then determine, in accordance with the procedures set forth above, whether the transaction may proceed. This preclearance policy applies even if you are initiating a transaction outside of a Blackout Period (as defined below).

The Approving Persons are under no obligation to approve a transaction submitted for pre-clearance and may determine not to permit a transaction, even if it would not violate the federal securities laws or a specific provision of this policy. In certain circumstances, other associates may be asked to clear with an Approving Person all proposed transactions before initiating them. The fact that a particular intended trade has been denied pre-clearance should be treated as confidential information and should not be disclosed to any person unless authorized by the Approving Person.

If a request for pre-clearance is approved, you have three business days to effect the transaction (or, if sooner, before commencement of a quarterly or event-specific restricted period). Under no circumstance may a person trade while aware of material non-public information about the Company, even if pre-cleared. Thus, if you become aware of material non-public information after receiving pre-clearance, but before the trade has been executed, you must not effect the pre-cleared transaction. If a proposed transaction is not approved under the pre-clearance policy, you should refrain from initiating any transaction in Company securities, and you should not inform anyone within or outside of the Company of the restriction.

The Company's approval of any particular transaction under this pre-clearance procedure does not insulate any Restricted Person from liability under the securities laws. Under the law, the ultimate responsibility for determining whether an individual is aware of material nonpublic information about the Company rests with that individual in all cases.

b. Blackout Periods

In order to avoid the appearance of impropriety, no director, officer or employee of the Company is permitted to, directly or indirectly or through family members or other persons or entities, buy or sell securities of the Company during any of the four "blackout periods" described below unless such purchase or sale is made pursuant to a predetermined plan for trades of specified amounts of the Company's common stock in accordance with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, which was implemented at a time when the director, officer or employee was not in possession of material non-public information about the Company (a "10b5-1 Plan").

The four "blackout periods" for the quarterly periods ending March 31st, June 30th and September 30th and the annual period ending December 31st of each year shall begin on the 21st calendar day (28th calendar day for the annual period ending December 31) prior to the internal target date set by Company management for the first release by the Company of financial or operating results for such fiscal quarterly or annual period and shall end at the beginning of the third trading day on the NYSE following the date of the Company's public announcement of its financial and operating results for the applicable preceding fiscal period.

If, however, the blackout period commences on a non-trading day (i.e., a Saturday, Sunday or NYSE holiday), the blackout period will commence on the completion of the next full trading day.

c. Rule 10b5-1 Trading Plans

Rule 10b5-1 provides for an affirmative defense against insider trading liability if trades occur pursuant to a prearranged “trading plan” that meets specified conditions.

Under Rule 10b5-1, if you enter into a binding contract, an instruction or a written plan that specifies the amount, price and date on which securities are to be purchased or sold, and these arrangements are established at a time when you are not aware of material non-public information, you may claim a defense to insider trading liability if the transactions under the trading plan occur at a time when you have subsequently learned material non-public information. A plan effected in accordance with the rule may specify amount, price and date through a formula or may specify trading parameters which another person has discretion to administer, but you must not exercise any subsequent discretion affecting the transactions, and if your broker or any other person exercises discretion in implementing the trades, you must not influence his or her actions and he or she must not be aware of any material non-public information at the time of the trades. Trading plans can be established for a single trade or a series of trades.

It is important that you properly document the details of a trading plan. Note that, in addition to the requirements described above, there are a number of additional procedural conditions to Rule 10b5-1 that must be satisfied before you can rely on a trading plan as an affirmative defense against an insider trading charge. These requirements include that you act in good faith, that you do not modify your trading instructions while you are aware of material non-public information and that you not enter into or alter a corresponding or hedging transaction or position. Because this rule is complex, the Company recommends that you work with a broker and be sure you fully understand the limitations and conditions of the rule before you establish a trading plan.

All Rule 10b5-1 trading plans, contracts and instructions are required to be reviewed and approved by the General Counsel for compliance with Rule 10b5-1 and the Company’s policies concerning such programs, prior to implementing any such plan, contract or instruction. In addition, all amendments, modifications and terminations of an existing Rule 10b5-1 trading plan must be reviewed and approved by the General Counsel prior to effecting any such amendments, modifications or terminations. Note that (i) a 10b5-1 trading plan should have a duration of at least six months and no more than two years; (ii) you may enter into only one 10b5-1 plan at the same time (i.e., overlapping plans are not permitted); and (iii) you should not sell Company’s securities outside of a 10b5-1 trading plan while such 10b5-1 trading plan is in effect, unless the latter requirement is waived or modified by the General Counsel or his or her designee in his or her sole discretion.

As such, if you wish to implement a trading plan pursuant to Rule 10b5-1 under the 1934 Act, you must first pre-clear the plan with the General Counsel at least five trading days prior to the entry into the plan. A Rule 10b5-1 trading plan can only be entered into, amended, modified or terminated during outside of any Blackout Period and at a time when you are not aware of material non-public information. In order to help demonstrate that you were not aware of material non-public information at the time you entered into a Rule 10b5-1 trading plan, trades may not commence under a Rule 10b5-1 plan until at least 30 days after adoption of the plan.

Amendments of an existing Rule 10b5-1 trading plan are strongly discouraged due to legal risks. Amendment of a plan can affect the validity of trades that have taken place under the plan prior to amendment. Amendments must be approved outside of any Blackout Period by the General Counsel in writing. Amendments will be treated as a termination of the current plan and creation of a new plan, and will be subject to all requirements regarding establishment of new plans. The first trade under an amended plan may not occur until at least 30 days after the date of amendment of the plan, except as approved by the General Counsel.

Terminations of Rule 10b5-1 trading plans are also strongly discouraged due to legal risks. If you still wish to terminate your plan, you must notify the General Counsel in advance and obtain approval in writing. If you terminate a plan, you may not enter into another plan until at least 30 days after the termination date of the prior plan or before trading outside of the Rule 10b5-1 plan (which may mean waiting until after the next Blackout Period), except as approved by the General Counsel. The creation of a new plan will be subject to all requirements regarding establishment of new plans. The General Counsel may deny approval of a new plan after the early termination of an existing plan if you have exhibited a pattern of early termination or have adopted a series of short-term plans.

Transactions pursuant to Rule 10b5-1 trading plans that are effected in accordance with this Policy may occur notwithstanding the other prohibitions included herein.

d. Additional Matters

All directors, officers, and employees will be required to certify their understanding of and intent to comply with this Policy periodically. Anyone who fails to comply with this Policy or who refuses to certify that he or she has complied with it will be subject to appropriate disciplinary action, up to and including termination of employment.

This Policy will continue to apply to your transactions in Company securities after your employment or service has terminated with the Company until such time as you are no longer aware of material non-public information or until that information has been publicly disclosed or is no longer material.

CODE OF ETHICS FOR CEO AND SENIOR FINANCIAL OFFICERS

The Company has a Code of Business Conduct and Ethics applicable to all directors and employees of the Company. The provisions set forth therein relating to ethical conduct, conflicts of interest and compliance with law, bind the CEO and all senior financial officers, including the CFO, principal accounting officer, controller, or persons performing similar functions. In addition to the Code of Business Conduct and Ethics, the CEO and senior financial officers will be bound to:

- Engage in and promote honest and ethical conduct, including the ethical handling of actual and apparent conflicts of interest between personal and professional relationships.

- Avoid conflicts of interest and to disclose to the Chairman of the Audit Committee any material transaction or relationship that reasonably could be expected to give rise to such a conflict.

- Promptly provide information that is accurate, complete, objective, relevant, timely and understandable to ensure full, fair, accurate, timely, and understandable disclosure in reports and documents that the Company files with, or submits to, government agencies (including the Securities and Exchange Commission) and in the Company's other public communications.

- Comply with laws, rules and regulations of federal, state, provincial and local governments, and other appropriate private and public regulatory agencies.

- Act in good faith, responsibly, with due care, competence and diligence, and not take any action to fraudulently influence, coerce, manipulate or mislead the Company's independent public auditors for the purpose of rendering the financial statements of the Company misleading.

- Respect the confidentiality of information acquired in the course of one's work except when authorized or otherwise legally obligated to disclose such information.

- Not use confidential information acquired in the course of one's work for personal advantage.

- Promptly report to the Chairman of the Audit Committee any conduct that the individual believes to be a violation of law or business ethics or of any provision of the Code of Business Conduct and Ethics or this Code of Ethics.

- Comply with the reporting obligations of Section 16(a) of the Securities Exchange Act of 1934, as amended, the rules and regulations promulgated thereunder, and of all other applicable laws, rules and regulations.

The CEO and senior financial officers will be held accountable to this Code of Ethics. Any failure to observe the terms of this Code of Ethics may result in disciplinary action, up to and including termination of employment. Violations of this Code of Ethics may also constitute violations of law and may result in civil and criminal penalties for you, your supervisors and/or the Company.

If you have any questions regarding the best course of action in a particular situation, you should promptly contact the Chairman of the Audit Committee and/or the Company's General Counsel. You may choose to remain anonymous in reporting any possible violation of this Code of Ethics.

Exhibit 21.1

SUBSIDIARIES OF W&T OFFSHORE, INC.

The subsidiaries of W&T Offshore, Inc. are listed below.

Name	State of Organization	Percent Owned
Aquasition Energy LLC	Delaware	100.0%
Aquasition LLC	Delaware	100.0%
Aquasition II LLC	Delaware	100.0%
Aquasition III LLC	Delaware	100.0%
Aquasition IV LLC	Delaware	100.0%
Aquasition V LLC	Delaware	100.0%
Falcon Aero Holdco LLC	Delaware	100.0%
Falcon Aero Holdings LLC	Delaware	100.0%
Green Hell LLC	Delaware	100.0%
Seaquester LLC	Delaware	100.0%
Seaquestration LLC	Delaware	100.0%
W & T Energy VI, LLC	Delaware	100.0%
W & T Energy VII, LLC	Delaware	100.0%
White Shoal Pipeline Corporation	Delaware	73.4%

Exhibit 22.1

LIST OF SUBSIDIARY GUARANTORS

Each of the following subsidiaries of W&T Offshore, Inc. (the "Company") is a subsidiary guarantor with respect to the 10.75% Senior Second Lien Notes due 2029 (the "2029 Notes") issued by the Company.

Name	State of Organization
Aquasition Energy LLC	Delaware
Aquasition LLC	Delaware
Aquasition II LLC	Delaware
Aquasition III LLC	Delaware
Aquasition IV LLC	Delaware
Aquasition V LLC	Delaware
Falcon Aero Holdco LLC	Delaware
Falcon Aero Holdings LLC	Delaware
Green Hell LLC	Delaware
Seaquester LLC	Delaware
Seaquestration LLC	Delaware
W & T Energy VI, LLC	Delaware
W & T Energy VII, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-214168 and 333-282595 on Form S-3 and Registration Statement Nos. 333-219747 and 333-272794 on Form S-8 of our reports dated March 4, 2025, relating to the financial statements of W&T Offshore, Inc. and the effectiveness of W&T Offshore, Inc.’s internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2024.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 4, 2025

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-214168) of W&T Offshore, Inc.,

(2) Registration Statement (Form S-8 No. 333-219747) pertaining to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, as amended,

(3) Registration Statement (Form S-8 No. 333-272794) pertaining to W&T Offshore, Inc. 2023 Incentive Compensation Plan, and

(4) Registration Statement (Form S-3 No. 333-282595) of W&T Offshore, Inc.;

of our report dated March 6, 2024, with respect to the consolidated financial statements of W&T Offshore, Inc. and subsidiaries included in this Annual Report (Form 10-K) of W&T Offshore, Inc., for the year ended December 31, 2024.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 4, 2025

Exhibit 23.3

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent consultants, Netherland, Sewell & Associates, Inc. hereby consents to the incorporation by reference in the Annual Report on Form 10-K of W&T Offshore, Inc. to be filed on or about March 4, 2025, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated January 29, 2025, and entitled "Estimates of Reserves and Future Revenue to the W&T Offshore, Inc. Interest in Certain Oil and Gas Properties Located in State Waters Offshore Alabama, Louisiana, and Texas, and in the Gulf of Mexico as of December 31, 2024", and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2020, 2021, 2022, 2023 and 2024. We further consent to the incorporation by reference of information contained in our report dated January 29, 2025, in Registration Statements Nos. 333-214168 and 333-282595 on Form S-3 and Registration Statements Nos. 333-219747 and 333-272794 on Form S-8. We also consent to W&T Offshore, Inc.'s use of the phrase "independent petroleum consultant" as referencing Netherland, Sewell & Associates, Inc.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By:/s/ Eric J. Stevens, P.E.
Eric J. Stevens, P.E.
President and Chief Operating Officer

Dallas, Texas
March 4, 2025

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13a – 14(a) AND 15d – 14(a)
OF §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tracy W. Krohn, certify that:

1. I have reviewed this Annual Report on Form 10-K of W&T Offshore, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 4, 2025

/s/ Tracy W. Krohn
Tracy W. Krohn
Chairman, Chief Executive Officer, President and Director
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a – 14(a) AND 15d – 14(a)
OF §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Sameer Parasnis, certify that:

1. I have reviewed this Annual Report on Form 10-K of W&T Offshore, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 4, 2025

/s/ Sameer Parasnis
Sameer Parasnis
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. § 1350, AS ADOPTED
PURSUANT TO §906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Annual Report on Form 10-K for the year ended December 31, 2024 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 4, 2025

/s/ Tracy W. Krohn
Tracy W. Krohn
Chairman, Chief Executive Officer, President and Director
(Principal Executive Officer)

Date: March 4, 2025

/s/ Sameer Parasnis
Sameer Parasnis
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 29, 2025

Mr. Matthew W. McFarland
W&T Offshore, Inc.
5718 Westheimer Road, Suite 700
Houston, Texas 77057

Dear Mr. McFarland:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2024, to the W&T Offshore, Inc. (W&T) interest in certain oil and gas properties located in state waters offshore Alabama, Louisiana, and Texas and in federal waters in the Gulf of Mexico. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by W&T. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, except that future income taxes are excluded and, as requested, abandonment costs have not been included in our estimates of future net revenue. Definitions are presented immediately following this letter. This report has been prepared for W&T Offshore, Inc.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

For fields included in the Monza Joint Venture (Monza JV), the net reserves and future net revenue to the W&T interest have been estimated incorporating the terms of the Monza JV using the proportional consolidation method. W&T entered into the Monza JV on February 23, 2018. Under the proportional consolidation method, W&T's interest share of revenues, expenses, investments, and liabilities includes both W&T's direct interest in the properties and W&T's interest share of the Monza JV.

We estimate the net reserves and future net revenue to the W&T interest in these properties, as of December 31, 2024, to be:

	Net Reserves			Future Net Revenue[1] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	19,546.5	8,246.8	229,445.2	691,039.0	549,756.6
Proved Developed Non-Producing	17,507.1	3,990.3	106,614.4	863,584.9	520,719.4
Proved Undeveloped	14,587.4	759.5	38,361.8	380,067.5	158,981.7
Total Proved	51,641.0	12,996.5	374,421.4	1,934,691.4	1,229,457.7

Totals may not add because of rounding.

(1) Future net revenue does not include estimated abandonment costs.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. Estimates of proved undeveloped reserves have been included for four proved locations that are scheduled to be drilled more than five years beyond the original booking dates because of limitations with conductor slot availability. These locations have been included based on W&T's declared intent to drill these wells. Also, estimates of proved undeveloped reserves have been included for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant price and cost parameters discussed in subsequent paragraphs of this letter. These locations have been included based on the W&T's declared intent to drill these wells, as evidenced by W&T's internal budget, reserves estimates, and price forecast. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. It is our understanding W&T has divested their interest in Garden Banks Blocks 385 and 386, which closed on January 9, 2025, and was effective as of December 1, 2024. The reserves and future revenue from these blocks are included in this report in field GB 386 and represent less than one percent of total proved reserves.

Gross revenue is W&T's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for W&T's share of state production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January 2024 through December 2024. For oil and NGL volumes, the average West Texas Intermediate spot price of $76.32 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.130 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $74.69 per barrel of oil, $22.98 per barrel of NGL, and $2.584 per MCF of gas.

Operating costs used in this report are based on operating expense records of W&T. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and W&T's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Economic projections are included to account for the fees associated with W&T's oil transportation contracts for Green Canyon 859 Field. For all other areas, we have made no specific investigation of any firm transportation contracts that may be in place and our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation. As requested, the field-level costs are allocated by month among the proved reserves categories.

Capital costs used in this report were provided by W&T and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of W&T's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the W&T interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on W&T receiving its net revenue interest share of estimated future gross production after field usage and shrinkage.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by W&T, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, petrophysical data, seismic data, well test data, production data, bottomhole pressure data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for non-producing zones and undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from W&T, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Michael J. Kingrey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2015 and has over 6 years of prior industry experience. Ruurdjan (Rudi) de Zoeten, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 18 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ Michael J. Kingrey
Michael J. Kingrey, P.E. 128848
Vice President

Date Signed: January 29, 2025

By: /s/ Ruurdjan (Rudi) de Zoeten
Ruurdjan (Rudi) de Zoeten, P.G. 3179
Vice President

Date Signed: January 29, 2025

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DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties*. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources 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, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *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.

(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.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, 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.

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

(10) *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. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

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

(15) *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. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(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 (a)(22)(iii) of this section, 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.

(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.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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 (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *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 occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(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 the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible 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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *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.

(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 (a)(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).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
> f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

(28) *Resources.* Resources are quantities of oil and 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 to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(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.

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
>
> *Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
> - *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(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.

(32) *Unproved properties.* Properties with no proved reserves.