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, 2023

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 $337,554,623 based on the closing sale price of $3.87 per share as reported by the New York Stock Exchange on June 30, 2023.

The number of shares of the registrant's common stock outstanding on February 29, 2024 was 146,857,277.

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 may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and our development program. 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. Depressed oil, NGL and 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.
- 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. 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.

Operating Risks

- Relatively short production periods for our Gulf of Mexico properties based on proved reserves subject us to high reserve replacement needs and require significant capital expenditures to replace our proved reserves at a faster rate than companies whose proved reserves have longer production periods. If we are not able to obtain new oil and gas leases or replace reserves, we will not be able to sustain production at current levels, which may have a material adverse effect on our business, financial condition, or results of operations.
- 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 Mexico, which presents unique operating risks.
- Continuing inflation and cost increases may impact our sales margins and profitability.
- 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.
- The geographic concentration of our properties in the Gulf of Mexico subjects us to an increased risk of loss of revenues or curtailment of production from factors specifically affecting the Gulf of Mexico, including hurricanes.
- 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. 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.
- 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 targeted acquisitions. Such acquisitions 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.
- We have historically outsourced substantially all of our information technology infrastructure and the management and servicing of such infrastructure to a limited number of third parties, which makes us more dependent upon such third parties and exposed to related risks. We are in the process of transitioning substantially all of such infrastructure internally or to other service providers, which subjects us to increased costs and risks.
- 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

- We have a significant amount of indebtedness and limited borrowing capacity under our Credit Agreement. Our leverage and debt service obligations may have a material adverse effect on our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.
- 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, and our ability to access the capital and credit markets to raise capital or refinance our existing indebtedness on favorable terms, including our 11.75% Notes and our Credit Agreement with Calculus, 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 11.75% 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.
- We may be limited in our ability to maintain or recognize additional proved undeveloped reserves under current SEC guidance.
- Additional deepwater drilling laws, regulations and other restrictions, delays and other offshore-related developments in the Gulf of Mexico 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. 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.
- 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 natural gas and oil 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.

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.

GAAP. Accounting principles generally accepted in the United States of America.

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.

OCS block. A unit of defined area for purposes of management of offshore petroleum exploration and production by the BOEM.

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 properties. Properties with proved reserves.

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. The Securities and Exchange Commission.

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. is an independent oil and natural gas producer, active in the acquisition, exploration and development of oil and natural gas properties in the Gulf of Mexico. W&T Offshore, Inc. is a Texas corporation originally organized as a Nevada corporation in 1988, and successor by merger to W&T Oil Properties, Inc., a Louisiana corporation organized in 1983.

Since our founding in 1983 by our Chairman and CEO, Tracy Krohn, we have continually grown our footprint in the Gulf of Mexico through acquisitions, exploration and development. As of December 31, 2023 we held working interests in 53 offshore producing fields in federal and state waters. Our acreage, well, production and reserves information are described in more detail under Part I, Item 2. *Properties,* in this Form 10-K. Our working interests in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. and our wholly-owned subsidiaries, Aquasition LLC ("A-I LLC"), Aquasition II LLC ("A-II LLC"), and W&T Energy VI, LLC, Delaware limited liability companies and through our proportionately consolidated interest in Monza Energy, LLC ("Monza").

For the past four decades, we have developed significant technical expertise in finding and developing properties in the Gulf of Mexico with existing production which provide the best opportunity to achieve a rapid return on our invested capital. We have successfully discovered and produced properties on the conventional shelf and in the deepwater across the Gulf of Mexico.

Business Strategy

The Gulf of Mexico 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 Mexico 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 Mexico 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 169 structures (108 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.

- *Manage environmental, social, and governance matters.* With ultimate oversight by our board of directors, Environmental, Social & Governance ("ESG") matters are an integral part of our day-to-day operations and are incorporated into the strategic decision-making process across our business. We have established a managerial ESG Task Force composed of cross-functional management-level employees in Operations, Health, Safety, Environmental and Regulatory ("HSE&R"), Legal, Human Resources and Finance. This task force is responsible for overseeing and managing our ESG reporting initiatives and suggesting areas of focus to our executive management. Executive management in turn reports on those activities to the ESG Committee of our board of directors. We strive to execute our business plan while simultaneously reducing our environmental footprint, including emissions, potential spills and other impacts. With respect to social priorities, we maintain a company-wide diversity training program and focus on promoting diversity and inclusion. Relating to governance, our fundamental policy is to conduct our business with honesty and integrity in accordance with high legal and ethical standards. In 2023, we published our third annual ESG report highlighting our performance and initiatives across ESG categories for the period of 2020 to 2022, which is not incorporated into, and does not form a part of, this Form 10-K. Finally, ESG performance scores are a factor in determining compensation for all management-level employees.

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

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

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

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

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

- Carrying 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 also face increasing indirect competition from alternative energy sources, including wind, solar, and electric power. We currently operate in the Gulf of Mexico and compete for the acquisition of oil and natural gas properties and lease sales primarily on the basis of price for such properties. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas companies and individual producers and operators. Many of these competitors are large, well-established companies that have financial and other resources substantially greater than ours and a greater ability to provide the extensive regulatory financial assurances required for offshore properties. Our ability to acquire additional oil and natural gas properties, acquire additional leases and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties, finance investments and consummate transactions in a highly competitive environment.

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 2023, approximately 41% of our revenues were received from BP Products North America and approximately 13% from Chevron-Texaco, with no other customer comprising greater than 10% of our 2023 revenues. Given the commoditized nature of the products we produce and market and the location of our production in the Gulf of Mexico, 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.

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, among others, 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 $12.5 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.

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 Mexico 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.

Leasing. The federal government cannot conduct offshore lease sales without the development and approval of a National Outer Continental Shelf Oil and Gas Leasing Program (an "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 January 2021, President Biden issued an executive order suspending new leasing activities for oil and natural gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and natural gas permitting and leasing practices. Lease Sale 257 was originally scheduled to be held in March 2021, but the decision to hold the sale was rescinded after the issuance of the executive order. After a group of states challenged the executive order and a federal judge required the DOI to stop the leasing pause, Lease Sale 257 was rescheduled and held in November 2021. In January 2022, the D.C. District Court vacated Lease Sale 257, ruling that it violated the National Environmental Policy Act. In August 2023, the D.C. Circuit Court of Appeals reversed the D.C. District Court's order vacating Lease Sale 257 and ruled the highest bidders would receive the leases auctioned in Lease Sale 257.

In August 2022, Congress passed the Inflation Reduction Act (the "IRA"), which required the BOEM to offer at least two million acres for oil and natural gas leasing in the OCS. The IRA required the DOI to move forward with Lease Sales 259 and 261 in the Gulf of Mexico. Lease Sale 259 was held in March 2023, and Lease Sale 261 was held in December 2023. 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 November 2021, the DOI released its report on federal oil and natural gas leasing and permitting practices. The report included recommendations in respect to the offshore sector, including adjusting royalty rates to ensure that the full value of leased tracts are captured, strengthening financial assurance coverage amounts that are required by operators, and establishing "fitness to operate" criteria that companies would need to meet in respect of safety, environmental and financial responsibilities in order to operate in the OCS.

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 Mexico scheduled in 2025, 2027 and 2029.

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. Currently the BOEM requires all lessees of an OCS oil and natural gas lease to post base bonds ranging from $50 thousand to $3.0 million in addition to supplemental financial assurance determined based on the lessee's ability to carry out present and future financial obligations. In June 2023, the BOEM proposed a new rule that updated the criteria for determining whether oil and natural gas lessees may be required to provide supplemental financial assurance above the prescribed base financial assurance to ensure compliance with the OCSLA. The rule proposes to consider an OCS lessee's credit rating and proved oil reserves in determining whether a lessee in the OCS is required to obtain supplemental financial assurance. A final rule is anticipated in April 2024. See Part II, Item 8. *Financial Statements and Supplementary Data —Note 17 — Commitments* for more information on decommissioning and financial assurance requirements.

Regulation and transportation of natural gas. Our sales of 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 regulation. The Federal Energy Regulatory Commission (the "FERC") has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. *636*, issued in 1992, the interstate natural gas transportation and marketing system allows non-pipeline natural gas sellers, including producers, to effectively compete with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the effect of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. The rates for such storage and transportation services are subject to the FERC ratemaking authority, and the FERC may apply cost-of-service principles or allow a pipeline to negotiate rates. Similarly, the natural gas pipeline industry is subject to state regulations, which may change from time to time.

The OCSLA, which is administered by the BOEM and 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. The BOEM issued a final rule, effective August 2008, which implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines in the OCS.

In 2007, the FERC issued rules ("Order 704") requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales and purchases to the FERC to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with the FERC's policy statement on price reporting. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state legislatures, state commissions and the courts. The natural gas industry historically has been very heavily regulated. As a result, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and the states will continue.

While these federal and state regulations for the most part affect us only indirectly, they are intended to enhance competition in natural gas markets. We cannot predict what further action the FERC, the BOEM or state regulators will take on these matters. However, we do not believe that any such action taken will affect us differently, in any material way, than other natural gas producers with which we compete.

Oil and NGLs transportation rates. 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. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction. The price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for oil, condensate, NGLs and other products are regulated by the FERC. In general, interstate oil, condensate and NGL 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 other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes and regulations. As it relates to intrastate oil, condensate and NGL pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally. We do not believe that the regulatory decisions or activities relating to interstate or intrastate oil, condensate or NGL pipelines will affect us in a way that materially differs from the way they affect other oil, condensate and NGL producers or marketers.

Climate Change. The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States. President Biden has made addressing climate change, including the restriction or elimination of greenhouse gas ("GHG") emissions, a priority in his administration.

The IRA includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems by 2024. In July 2023, the EPA proposed to expand the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas facilities, as required by the IRA. Among other things, the proposed rule would expand the emissions events that are subject to reporting requirements to include “other large release events” and apply reporting requirements to certain new sources and sectors. The rule is expected to be finalized in the spring of 2024 and become effective on January 1, 2025, in advance of the deadline for GHG reporting for 2024 (March 2025). In January 2024, the EPA proposed a new rule implementing the IRA’s methane emissions charge. The proposed rule includes potential methodologies for calculating the amount by which a facility’s reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the IRA. The methane emissions charge imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 would be $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 December 2023, the EPA announced new rules intended to reduce methane emissions from oil and natural gas sources. The final rule strengthens the existing emissions reduction requirements in Subpart OOOOa, expands reduction requirements for new, modified and reconstructed oil and natural gas sources in Subpart OOOOb, and imposes methane emissions limitations on existing oil and natural gas sources nationwide for the first time. In addition, the final rule establishes “Emissions Guidelines,” creating a Subpart OOOOc that requires states to develop plans to reduce methane emissions from existing sources which must be at least as effective as presumptive standards set by the EPA. The final rule also creates a third-party monitoring program to flag large emissions events, referred to as “super emitters.” Under Subparts OOOOb and OOOOc, the final rule establishes more stringent requirements for new, modified and reconstructed sources “constructed” after December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance dates. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane emissions from existing sources. The final Emissions Guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply. The new rule is likely to increase costs and regulatory burdens on the oil and natural gas industry, especially for smaller operators and operators of older oil and natural gas wells.

In March 2022, the SEC issued a proposed rule regarding the enhancement and standardization of mandatory climate-related disclosures. The proposed rule would require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to:

- climate-related risks and their actual or likely material impacts on the registrant’s business, strategy, and outlook;
- the registrant’s governance of climate-related risks and relevant risk management processes;
- the registrant’s GHG emissions, which, for accelerated and large accelerated filers and with respect to certain emissions, would be subject to assurance;
- certain climate-related financial statement metrics and related disclosures in a note to its audited financial statements; and
- information about climate-related targets and goals, and the registrant’s transition plan, if any.

Although the proposed rule’s ultimate date of effectiveness and the final form and substance of these requirements is not yet known and the ultimate scope and impact on our business is uncertain, compliance with the proposed rule, if finalized, may result in increased legal, accounting and financial compliance costs, make some activities more difficult, time-consuming and costly, and place strain on our personnel, systems and resources.

In addition to the regulations discussed above, the OCSLA authorizes the DOI to regulate activities authorized by the BOEM in the Central and Western Gulf of Mexico. The EPA retains jurisdiction over all other parts of the OCS. Under the OCSLA, the DOI is limited to regulating offshore emissions of criteria pollutants and their precursor-pollutants to the extent they significantly affect the air quality of any state. The BSEE conducts field inspections of emission sources installed on offshore platforms that have the potential to emit regulated air pollutants. The BSEE also reviews BOEM-mandated monitoring and reporting of air emission sources for compliance with approved plan emission limits. The BSEE may compel measures to control and bring into compliance those operations determined to be in violation of applicable regulations or plan conditions by issuing Incidents of Noncompliance or recommending further enforcement action against potential violators.

The threat of climate change also continues to attract considerable public, governmental and scientific attention in foreign countries. Numerous proposals have been made at the international levels of government to monitor and limit emissions of GHG as well as to restrict or eliminate future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, policies and incentives to encourage the use of renewable energy or alternative low-carbon fuels and regulations that directly limit GHG emissions from certain sources. In addition, there exist numerous conventions and non-binding commitments of participating nations with goals of limiting their GHG emissions and fossil fuel subsidies. These include the United Nations-sponsored Paris Agreement, which requires signatory countries to set voluntary, individually-determined reduction goals and the Glasgow Climate Pact, which stated long-term global goals (including those in the Paris Agreement) to limit the increase in the global average temperature and emphasized reductions in GHG emissions. Most recently, at the 28th Conference of the Parties (“COP28”), member countries entered into an agreement that calls for actions toward achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement include, among other things, accelerating efforts toward the phase-down of unabated coal power, phasing out inefficient fossil fuel subsidies and other measures that drive the transition away from fossil fuels in energy systems. In February 2021, the Biden administration rejoined the Paris Agreement. Pursuant to its obligations as a signatory to the Paris Agreement, the United States has set a target to reduce its GHG emissions by 50% to 52% by the year 2030 as compared with 2005 levels and has agreed to provide periodic updates on its progress. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement. In addition, in November 2021, the United States signed the Global Methane Pledge, a pact that aims to reduce global methane emissions by at least 30% below 2020 levels by 2030.The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement, the Glasgow Climate Pact and the COP28 agreement, or other international conventions cannot be predicted at this time.

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.

Seasonality and Inflation

Seasonality. 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 into storage facilities a portion of their anticipated winter requirements of natural gas. 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 Mexico 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.

Inflation. 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.

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 2023 was 3.4%. These inflationary pressures have caused the Federal Reserve to tighten monetary policy by approving a series of increases to the Federal Funds Rate. As of December 31, 2023, the Federal Reserve benchmark rate ranges from 5.25% to 5.50%. Although the Federal Reserve has stated that they will begin reducing the benchmark rate in 2024, if inflation were to continue to rise, it is possible the Federal Reserve would continue to take action they deem necessary to bring inflation down and to ensure price stability, including further 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.

Human Capital Resources

As of December 31, 2023, we had 395 employees and employed an additional 326 individuals who are employees of third parties that primarily provide skilled labor in support of our field operations. This combined workforce conducts our business in Texas, Alabama, Louisiana and the Gulf of Mexico. 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 Mexico 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. 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.

Our policies and practices support diversity of thought, perspective, sexual orientation, gender, gender identity and expression, race, ethnicity, culture and professional experience. 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 tables below present, by category of employee, the gender and ethnicity composition of our employees as of December 31, 2023:

Category	Female	Male
Exec/Sr. Manager	17 %	83 %
Mid-Level Manager	27 %	73 %
Professionals	37 %	63 %
All Other	8 %	92 %

US Ethnicity	Exec/ Sr. Manager	Mid-Level Manager	Professionals	All Other
Asian	17 %	8 %	13 %	<1 %
Black/African American	17 %	6 %	16 %	5 %
Hispanic/Latino	17 %	6 %	6 %	6 %
Two or more races	—	2 %	—	<1 %
White	50 %	79 %	64 %	88 %

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 2023 total recordable incident rate for employees was 0.25, which is far below the industry average for the Gulf of Mexico from 2022 of 0.88. 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 Mexico, 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 10 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, NGL 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:

- 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;
- the actions of 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);
- 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.

These factors and the volatility of the energy markets, which we expect to continue, make it extremely difficult to predict future commodity prices with any certainty.

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 2023, 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 oil and natural gas, we have entered, and may continue to enter, into oil and natural gas price commodity derivative positions with respect to a portion of our expected future production. See *Financial Statements and Supplementary Data– Note 4 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information on our derivative contracts and transactions. We may enter into more derivative contracts in the future. While these commodity derivative positions are intended to reduce the effects of oil and natural gas price volatility, they may also limit future income if oil and natural gas 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 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, 2023, three fields, accounting for approximately 0.2 MMBoe (or 1.4%) of our 2023 production, 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.

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 Mexico, 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.

Furthermore, 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. We have, in the past, been required to shut in wells when tropical storms or hurricanes have caused or threatened damage to pipelines, gathering stations, and production facilities. In addition, certain third-party pipelines have submitted requests in the past to increase the fees they charge us to use these pipelines. These increased fees, if approved, could adversely impact our revenues or increase our operating costs, either of which would adversely impact our operating profits, cash flows and reserves.

Operating Risks

Relatively short production periods for our Gulf of Mexico properties based on proved reserves subject us to high reserve replacement needs and require significant capital expenditures to replace our proved reserves at a faster rate than companies whose proved reserves have longer production periods. If we are not able to obtain new oil and gas leases or replace reserves, we will not be able to sustain production at current levels, which may have a material adverse effect on our business, financial condition, or results of operations.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable in order to replace or grow our produced proved reserves. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves during the initial few years of production. All of our current production is from the Gulf of Mexico. Proved reserves in the Gulf of Mexico 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 proved undeveloped reserves between conventional and unconventional basins. Our independent petroleum consultant estimates that 33.2% of our total proved reserves as of December 31, 2023 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 Mexico. Historically, we have funded our capital expenditures and acquisitions with cash on hand, cash provided by operating activities, capital markets securities offerings and bank borrowings. The capital markets we have historically accessed may be constrained because of our leverage and also because, in recent years, institutional investors who provide financing to fossil fuel energy companies have become more attentive to sustainability lending practices and some of them may elect not to provide funding for fossil fuel energy companies. As a result, we may not be able to obtain sufficient funding to develop, find or acquire additional proved reserves in sufficient quantities to sustain our current production levels or to grow production beyond current levels. Future cash flows are subject to a number of variables, such as the level of production from existing wells, the prices of oil, NGLs and natural gas, and our success in developing and producing new reserves. Any reductions in our capital expenditures to stay within internally generated cash flow (which could be adversely affected if commodity prices decline) and cash on hand will make replacing depleted reserves more difficult.

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 addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. Currently 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 $35.0 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.

In the past, tropical storms and hurricanes in the Gulf of Mexico 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.

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

The deep shelf and the deepwater of the Gulf of Mexico 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.

Continuing inflation and cost increases may impact our sales margins and profitability.

Cost inflation, including significant increases in wholesale raw materials costs, labor rates, and domestic transportation costs have and could continue to impact profitability. In addition, our customers are also affected by inflation and the rising costs of goods and services used in their businesses, which could negatively impact their ability to purchase commodities such as oil and gas, which could adversely impact our revenue and profitability. Although such cost increases did not materially impact our 2023 financial condition or results of operations, and we currently do not expect them to materially impact our 2024 financial results or operations, there is no guarantee that we can increase selling prices, replace lost revenue, or reduce costs to fully mitigate the effect of inflation on our costs and business, which may adversely impact our sales margins and profitability.

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 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 Mexico subjects us to an increased risk of loss of revenues or curtailment of production from factors specifically affecting the Gulf of Mexico, 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 Mexico 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.

For 2023, approximately 40% of our production and 19% of our total revenue was attributable to our 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 2023, our Mobile Bay Properties were shut-in for 35 days for planned maintenance. The shut-in resulted in deferred production of approximately 774 MBoe based on production rates prior to the shut-in. 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.

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.

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, 2023.

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, 2023, approximately 16% 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 targeted acquisitions. Such acquisitions could expose us to potentially significant liabilities, including plugging and abandonment and decommissioning liabilities.

We expect to grow by expanding the exploitation and development of our existing assets, in addition to making targeted acquisitions in the Gulf of Mexico. We may not realize all of the anticipated benefits from 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.

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 infrastructure and management information systems to operate and record aspects of our business. Although we take 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.

We have historically outsourced substantially all of our information technology infrastructure and the management and servicing of such infrastructure to a limited number of third parties, which makes us more dependent upon such third parties and exposed to related risks. We are in the process of transitioning substantially all of such infrastructure internally or to other service providers, which subjects us to increased costs and risks.

We have historically outsourced substantially all of our information technology infrastructure and the management and servicing of such infrastructure to a limited number of third-party service providers. As a result, we previously relied on a small number of third parties that we do not control to ensure that our technology needs are sufficiently met, and cyber risks are effectively managed. This reliance has subjected us to certain cybersecurity risks arising from the loss of control over certain processes, including the potential misappropriation, destruction, corruption or unavailability of certain data and systems, such as confidential or proprietary information. A failure of any of our information technology service providers to perform its management and operational duties securely and effectively may have a material adverse effect on our financial condition, liquidity or results of operations or the integrity of the systems, processes and data needed to run our business. We also have not had written agreements with our primary service provider, which exposed us to additional risks with respect to the systems and data outsourced to such provider.

Beginning in August 2022, following the notification by our primary information technology service provider, All About IT ("AAIT"), of its intention to cease providing services to us, we began the transition of information technology services and infrastructure to us or to other providers. We have moved and are continuing to move certain services internally and are transitioning certain other services to new service providers and implementing agreements with such providers. Although the transition process is substantially complete and we no longer have a material relationship with AAIT, the transition process has disrupted, and may continue to disrupt, certain of our business operations. Any difficulties in completing such transition could impair our ability to monitor our production and accurately prepare our results of operations in a timely fashion. Moreover, such transition continues to expose us to additional risks, including increased costs, diversion of management's attention, disruptions to certain of our business operations and loss, damage to or unavailability of data or systems, each of which could have an adverse effect on our business and results of operations.

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 Chairman and Chief Executive Officer ("CEO") owns a significant portion of our common stock and an entity indirectly owned and controlled by our CEO is the sole lender under the Credit Agreement. 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

We have a significant amount of indebtedness and limited borrowing capacity under our current Credit Agreement. Our leverage and debt service obligations may have a material adverse effect on our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.

As of December 31, 2023, we had $400.2 million of principal amount of long-term debt outstanding, including the Term Loan, the 11.75% Senior Second Lien Notes, which mature on February 1, 2026 (the "11.75% Notes") and the TVPX Loan. We had no borrowings outstanding under our Credit Agreement.

Our leverage and debt service obligations could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit 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;
- limit our opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt obligations or to comply with any restrictive terms of our debt obligations;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- limit or impair our ability to obtain additional financing or refinancing in the future or require us to seek alternative financing, which may be more restrictive or expensive; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations. If new debt is added to our current debt levels, the related risks that we face could intensify. Additionally, availability of borrowings and letters of credit under our Credit Agreement is determined by establishment of a borrowing base, which is periodically redetermined in lender’s sole discretion based on our lender’s review of oil, NGLs and natural gas prices, our proved reserves and other criteria. Lower oil, NGLs and natural gas prices in the future would also adversely affect our cash flow and could result in reductions in our borrowing base and sources of alternate credit and affect our ability to satisfy the covenants and ratios required by the Credit Agreement and Indenture (as defined below). Lower oil, NGL and natural gas prices may also have ancillary impacts on us and certain subsidiaries. For example, W&T Offshore, Inc. pays certain expenses on behalf of the Aquasition Entities pursuant to a management services agreement, which expenses are repaid by the Aquasition Entities in the ordinary course from operating cash flows. Planned and unplanned facility downtime and lower gas prices in 2023 caused the Aquasition Entities to operate at a loss after servicing their debt obligations under the Subsidiary Credit Agreement, and the Aquasition Entities have been unable to fully reimburse W&T Offshore, Inc. for such expenses paid on their behalf. Because of restrictions in the Credit Agreement and in the 11.75% Notes, W&T Offshore, Inc. may not be able to fund expenses on behalf of the Aquasition Entities indefinitely.

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.

The indenture governing our 11.75% Notes (the “Indenture”), our Credit Agreement and our Subsidiary Credit Agreement governing our indebtedness 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 our restricted subsidiaries, among other things, to:

- make loans and investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of the Company;
- engage in transactions with our affiliates;
- pay dividends or make other distributions on capital stock or indebtedness; and
- create unrestricted subsidiaries.

Our 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 indentures governing our outstanding notes and our 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, and our ability to access the capital and credit markets to raise capital or refinance our existing indebtedness on favorable terms, including our 11.75% Notes and our Credit Agreement with Calculus, may be limited by industry conditions and financial markets.

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. Furthermore, we may not be able to refinance our 11.75% Notes or extend our Credit Agreement with Calculus on favorable terms or at all. 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 Credit Agreement and our outstanding 11.75% Notes are secured by various liens on our oil and natural gas properties, excluding our Mobile Bay assets. The oil and natural gas assets of, and equity in, certain of our subsidiaries that own our Mobile Bay assets (the Borrower Subsidiaries, as defined in *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K), are pledged on a first priority basis to secure our Term Loan. Any future borrowings under our Credit Agreement would be secured on a first priority basis by the assets securing the 11.75% Notes. In addition, we have certain rights to issue or incur additional or new secured debt, which could be secured by additional liens on the collateral. An issuance or incurrence of such additional secured debt would dilute the value of the collateral securing our outstanding secured debt. If the proceeds of the sale of the collateral securing the 11.75% Notes or any future indebtedness incurred under the 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 11.75% Notes upon a change of control.

If we experience certain kinds of changes of control, we must give holders of the 11.75% 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 Credit Agreement or other agreements we may enter into in the future may prevent us from applying funds to repurchase the 11.75% 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 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 at any time, on demand, at the surety's sole discretion. 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.

If we are required to provide additional collateral, 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, may be unable to execute our ARO plan or may be 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, local and foreign environmental 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 Mexico 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 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. Currently the BOEM requires all lessees of an OCS oil and natural gas lease to post base bonds ranging from $50 thousand to $3.0 million in addition to supplemental financial assurance determined based on the lessee’s ability to carry out present and future financial obligations. In June 2023, the BOEM proposed a new rule that updated the criteria for determining whether oil and natural gas lessees may be required to provide supplemental financial assurance above the prescribed base financial assurance to ensure compliance with the OCSLA. The proposed rule considers an OCS lessee’s credit rating and proved oil reserves in determining whether a lessee in the OCS is required to obtain supplemental financial assurance. A final rule is anticipated by April 2024. Additionally, the BOEM could in the future make new demands for additional financial assurances covering our obligations under our properties, which could exceed the Company’s capabilities to provide.

If we fail to comply with the proposed 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. 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. 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.

We may be limited in our ability to maintain or recognize additional proved undeveloped reserves under current SEC guidance.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves (“PUD reserves”) may only be booked if they relate to wells scheduled to be drilled within five years after the date of initial booking. This requirement may limit our ability to book additional PUD reserves as we pursue our drilling program. Moreover, we may be required to write down our PUD reserves if we do not drill those wells within the required five-year timeframe.

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

The Biden administration has taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations and those of the oil and natural gas industry more generally. Regulatory agencies under the Biden administration may issue new or amended rulemakings regarding deepwater leasing, permitting or drilling that 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 new 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, governmental agencies under the Biden administration are expected to continue to evaluate aspects of safety and operational performance in the Gulf of Mexico that could result in new, more restrictive requirements.

These regulatory actions, or any new rules, regulations, or legal or enforcement initiatives that impose more stringent operational standards could delay or disrupt our operations; result in increased supplemental bonding and costs; and limit activities in certain areas or cause us to incur penalties or fines; shut-in production at one or more of our facilities; or result in the suspension or cancellation of leases. Also, 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. 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 that are being pursued under the Biden administration.

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 Mexico 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 Mexico, 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 Mexico 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, 2023, we have $18.0 million of loss contingency recorded related to anticipated decommissioning obligations. See Part II, Item 8. *Financial Statements and Supplementary Data — Note 19 — 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. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year after. 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 has made addressing the threat of climate change from GHG emissions a priority under his administration. Regulatory agencies under the Biden administration have issued proposed rulemakings and may issue new or amended rulemakings in support of President Biden's regulatory and political agenda, which include reducing dependence on, and use of, fossil fuels and curtailment of hydraulic fracturing on federal lands.

Numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs as well as to eliminate such future emissions. Accordingly, our operations are 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 natural gas and oil exploration and development may be eliminated as a result of future legislation.

In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but have not been limited to, (i) the repeal of the percentage depletion allowance for natural gas and oil properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in recent federal tax legislation 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 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.

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 information technology ("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 W&T personnel including contractors and partners that perform functions or services that require securing W&T information assets, and to all devices and networks that are owned by W&T. 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.

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. In the past three years, we have not experienced a material information security breach but may in the future. 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.

Oil and Natural Gas Producing Activities

Our producing fields are located in federal and state waters in the Gulf of Mexico 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.

As of December 31, 2023, two of our fields located in the conventional shelf accounted for approximately 64.6% of our proved reserves on an energy equivalent basis. The following table provides information for these fields:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Percent of Total Company Proved Reserves
Mobile Bay Properties	0.2	10.1	320.4	63.7	51.8 %
Ship Shoal 349 (Mahogany)	11.7	1.0	18.7	15.8	12.8 %

The Mobile Bay Properties (as defined below) and Ship Shoal 349 field are two areas of operations of major significance, which we define as having year-end proved reserves of 10% or more of the Company's total proved reserves on an energy equivalent basis. Each area of operation of major significance is described in detail below. Unless indicated otherwise, "drilling" or "drilled" in the descriptions below refers to when the drilling reached target depth, as this measurement usually has a higher correlation to changes in proved reserves compared to using the SEC's definition for completion. The following are descriptions of these areas of operations:

Mobile Bay Properties

Our interests in certain oil and gas leasehold interests and associated wells and units located off the coast of Alabama, in state coastal and federal Gulf of Mexico waters approximately 70 miles south of Mobile, Alabama, are referred to as the "Mobile Bay Properties." Cumulative field production for the Mobile Bay Properties through 2023 is approximately 896.6 MMBoe gross. The Mobile Bay Properties produce from the Jurassic age Norphlet eolian sandstone at an average depth of 21,000 feet total vertical depth. As of December 31, 2023, 56 Norphlet wells have been drilled on the Mobile Bay Properties, 45 of which were successful and 27 of which are currently producing.

The following table presents our produced oil, NGLs and natural gas volumes (net to our interests) from the Mobile Bay Properties over the past three years:

	Year Ended December 31,		
	2023	2022	2021
Net Sales:			
Oil (MBbls)	15	17	29
NGLs (MBbls)	925	941	998
Natural gas (MMcf)	24,826	30,052	32,940
Total oil equivalent (MBoe)	5,078	5,967	6,516
Average realized sales prices:			
Oil ($/Bbl)	$ 41.12	$ 51.60	$ 27.49
NGLs ($/Bbl)	22.53	35.45	30.84
Natural gas ($/Mcf)	3.02	7.45	3.92
Oil equivalent ($/Boe)	18.98	43.25	24.68
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 17.39	$ 11.81	$ 7.34

(1) Includes lease operating expenses, gathering and transportation costs and plugging and abandonment costs.

Ship Shoal 349 Field (Mahogany)

Ship Shoal 349 field is located off the coast of Louisiana, approximately 235 miles southeast of New Orleans, Louisiana. The field area covers Ship Shoal federal OCS blocks 349 and 359, with a single production platform on Ship Shoal block 349 in 375 feet of water (the "Ship Shoal 349"). We own a 100% working interest in this field except for an interest in one well owned by Monza. Cumulative field production through 2023 is approximately 62.4 MMBoe gross. This field is a sub-salt development with nine productive horizons below salt at depths up to 18,000 feet. As of December 31, 2023, 31 wells have been drilled and 26 were successful. Since acquiring an interest and subsequently taking over as operator, we have directly participated in drilling 17 wells with a 100% success rate. There has been no drilling activity since 2019 at Ship Shoal 349.

The following table presents our produced oil, NGLs and natural gas volumes (net to our interests) from the Ship Shoal 349 field over the past three years:

	Year Ended December 31,		
	2023	2022	2021
Net Sales:			
Oil (MBbls)	1,269	1,313	1,667
NGLs (MBbls)	68	104	88
Natural gas (MMcf)	1,709	1,827	2,565
Total oil equivalent (MBoe)	1,622	1,722	2,182
Average realized sales prices:			
Oil ($/Bbl)	$ 70.86	$ 88.36	$ 65.27
NGLs ($/Bbl)	28.17	40.50	36.85
Natural gas ($/Mcf)	3.41	7.15	4.00
Oil equivalent ($/Boe)	60.22	71.03	56.05
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 7.61	$ 7.63	$ 6.60

(1) Includes lease operating expenses, gathering and transportation costs and plugging and abandonment costs.

Proved Reserves

Our proved reserves were estimated by Netherland, Sewell & Associates, Inc ("NSAI"), our independent petroleum consultant, and amounts provided in this Form 10-K are consistent with filings we make with other federal agencies. Our proved reserves as of December 31, 2023, 2022 and 2021 are summarized below:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	MMBoe	PV-10 (in millions)
December 31, 2023					
Proved developed producing	22.2	10.0	299.4	82.1	$ 750.1
Proved developed non-producing	5.2	2.7	80.0	21.2	204.1
Total proved developed	27.4	12.7	379.4	103.3	954.2
Proved undeveloped	9.6	1.0	54.6	19.7	126.7
Total proved	37.0	13.7	434.0	123.0	$ 1,080.9
December 31, 2022					
Proved developed producing	23.7	16.1	499.2	123.0	$ 2,280.8
Proved developed non-producing	7.4	1.5	76.8	21.8	457.6
Total proved developed	31.1	17.6	576.0	144.8	2,738.4
Proved undeveloped	9.5	1.3	58.6	20.5	390.2
Total proved	40.6	18.9	634.6	165.3	$ 3,128.6
December 31, 2021					
Proved developed producing	20.8	16.4	507.9	121.9	$ 1,185.3
Proved developed non-producing	6.8	1.4	41.3	15.1	222.9
Total proved developed	27.6	17.8	549.2	137.0	1,408.2
Proved undeveloped	9.6	1.3	58.4	20.6	213.7
Total proved	37.2	19.1	607.6	157.6	$ 1,621.9

In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2023 were determined to be economically producible under existing economic conditions, which requires the use of SEC pricing. Applying this methodology, the WTI oil average spot price of $78.21 per barrel and the Henry Hub natural gas average spot price of $2.64 per MMBtu were utilized as the referenced price and, after adjusting for quality, transportation, fees, energy content and regional price differences, the adjusted average product prices were $74.79 per barrel for oil, $24.08 per barrel for NGLs and $2.74 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 oil realized 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

Neither PV-10 nor PV-10 after ARO are financial measures defined under 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 after ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 after 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 after 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 after 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 after 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 after 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 reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves is as follows (in millions):

	December 31,		
	2023	2022	2021
PV-10	$ 1,080.9	$ 3,128.6	$ 1,621.9
Future income taxes, discounted at 10%	(151.0)	(594.1)	(224.8)
PV-10 before ARO	929.9	2,534.5	1,397.1
Present value of estimated ARO, discounted at 10%	(246.7)	(271.5)	(241.1)
Standardized measure	$ 683.2	$ 2,263.0	$ 1,156.0

Changes in Proved Reserves

The following table discloses our estimated changes in proved reserves during 2023:

	MMBoe
Proved reserves at December 31, 2022	165.3
Reserves additions (reductions):	
Revisions [(1)]	(32.2)
Purchases of minerals in place	2.6
Production	(12.7)
Net reserve additions (reductions)	(42.3)
Total proved reserves at December 31, 2023	123.0

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

See *Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2023. See *Financial Statements and Supplementary Data – Note 20 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

Our estimates of proved reserves, PV-10 and the standardized measure as December 31, 2023 are calculated based upon SEC mandated 2023 unweighted average first-day-of-the-month oil and natural gas benchmark prices, and adjusting for quality, transportation fees, energy content and regional price differentials, which may or may not represent current prices. If prices fall below the 2023 levels, absent significant proved reserve additions, this may reduce future estimated proved reserve volumes due to lower economic limits and economic return thresholds for undeveloped reserves, as well as impact our results of operations, cash flows, quarterly full cost impairment ceiling tests and volume-dependent depletion cost calculations. See *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 in this Form 10-K for additional information.

Proved Undeveloped Reserves

Our PUDs were estimated by NSAI, our independent petroleum consultant. Future development costs associated with our PUDs at December 31, 2023 were estimated at $437.9 million.

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

	December 31,		
	2023	2022	2021
PUDs, beginning of year	20.5	20.6	12.2
Revisions of previous estimates	(1.3)	(0.1)	8.4
Purchase of minerals in place	0.5	—	—
PUDs, end of year	19.7	20.5	20.6

The revisions of previous estimates during 2023 were due to changes in SEC pricing. The revisions in 2022 and 2021 were primarily due to technical revisions and revisions due to changes in SEC pricing at certain of our Ship Shoal fields.

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**
2024	1	14 %
2025	6	35 %
2026	4	48 %
2027	—	— %
2028+	1	3 %
Total	12	100 %

As of December 31, 2023, we believe that we will be able to develop all but 3.1 MMBoe (approximately 16%) of the total 19.7 MMBoe classified as PUDs within five years from the date such PUDs were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field ("Matterhorn"), Ship Shoal 349 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, Ship Shoal 349 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 2025 and 2035.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2023 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 W&T. 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 2013 and has over 14 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 30 years of oil and gas industry experience and has managed the preparation of public company reserve estimates the last 18 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, 2023:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	386,916	326,652	48,698	45,935	435,614	372,587
Deepwater	141,929	56,540	11,520	5,760	153,449	62,300
Alabama State Waters	8,038	5,144	—	—	8,038	5,144
Total	536,883	388,336	60,218	51,695	597,101	440,031

Our net acreage decreased 15,026 net acres (3%) from December 31, 2022 due to lease expirations offset by leases acquired in the September 2023 acquisition.

Approximately 88.3% 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
2024	17,122	34%
2025	8,813	17%
2026	—	0%
2027	15,760	30%
Thereafter	10,000	19%
Total	51,695	100%

In making decisions regarding drilling and operations activity for 2024 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

The information presented below is based on the SEC's criteria of completion or abandonment to determine wells drilled. Of the two gross (0.6 net) exploratory wells completed during 2022, one gross (0.3 net) well is currently producing. The following table sets forth our drilling activity for completed wells on a gross basis:

	Completed		
	2023	2022	2021
Conventional shelf	—	1	—
Deepwater	—	1	—
Wells operated by W&T	—	1	—

The following table summarizes our development and exploration offshore wells completed over the past three years:

	Year Ended December 31,		
	2023	2022	2021
Development wells completed:			
Gross wells	—	—	—
Net wells	—	—	—
Exploration wells completed:			
Gross wells	—	2	—
Net wells	—	0.6	—

During 2022, we completed one well and abandoned one well in which we had a 25% working interest. During 2021, we participated in the drilling of an exploration well which was non-commercial. Our success rate related to our development and exploration wells was 50% in 2022.

Capital Expenditures

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

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, 2023:

	Oil Wells (1)		Gas Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	110.0	101.3	86.0	76.8	196.0	178.1
Non-operated	33.0	5.8	12.0	5.4	45.0	11.2
Total	143.0	107.1	98.0	82.2	241.0	189.3

(1) Includes 10 gross (9.1 net) oil wells with multiple completions.

(2) Includes 6 gross (5.1 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 19 – 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

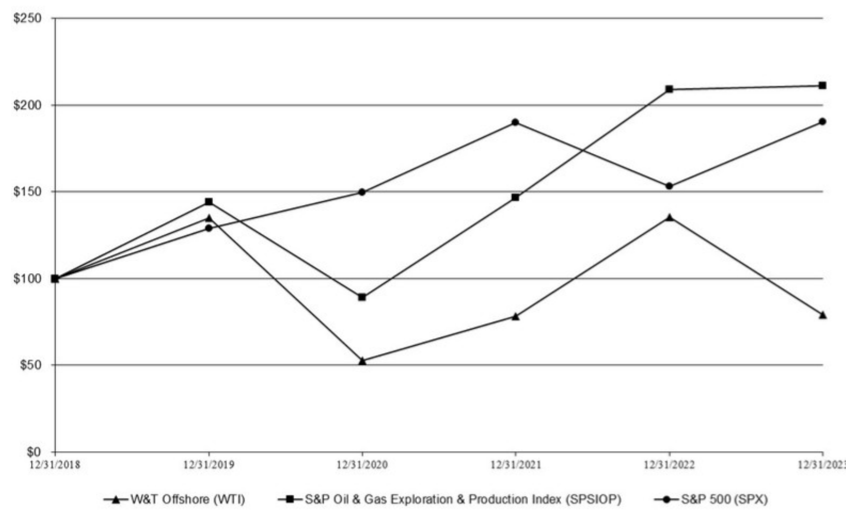
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of March 1, 2024, there were 134 registered holders of our common stock.

Dividends

On November 8, 2023, we announced that our board of directors approved the implementation of a quarterly cash dividend payable to holders of our common stock. The initial cash dividend of $0.01 per share of common stock, or $1.5 million, was paid on December 22, 2023, to shareholders of record at the close of business on November 28, 2023. Other than this dividend, we did not declare or pay any cash dividends on our common stock during 2023 and 2022. 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 graph below shows the cumulative total shareholder return assuming the investment of $100 in our common stock and the reinvestment of all dividends thereafter. 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.



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 2. *Properties*, Item 1A. *Risk Factors* 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 2023 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 2023 and 2022 items and comparisons between 2023 and 2022. Discussions of 2021 items and comparisons between 2022 and 2021 that are not included in the 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, 2022.

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 Mexico. As of December 31, 2023, we held working interests in 53 offshore producing fields in federal and state waters (which include 44 fields in federal waters and nine in state waters). We currently have under lease approximately 597,100 gross acres (440,000 net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 8,000 gross acres in Alabama state waters, 435,600 gross acres on the conventional shelf and approximately 153,500 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.

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.

Business Outlook

Our cash flows are materially impacted by the prices of commodities we produce (oil, NGLs and natural gas). During 2023, commodity prices experienced significant declines from those experienced during 2022. The average WTI oil price for 2023 was approximately 18% lower than the average for 2022 and the average Henry Hub natural gas price for 2023 was approximately 61% lower than the average for 2022. While the current outlook for commodity prices is favorable, other global factors could adversely impact our operations, and commodity prices could significantly decline from current levels.

In addition, the prices of goods and services used in our business can vary and impact our cash flows and margins. Our margins in 2023 decreased from 2022 primarily due to lower average realized commodity prices, coupled with higher operating expenses. We measure margins using an Adjusted EBITDA margin which we define as net income (loss) before income tax expense, net interest expense, depreciation, depletion, amortization and accretion, unrealized commodity derivative gain or loss and the effects of derivative premium payments, allowance for credit losses, non-cash incentive compensation, non-recurring costs related to IT services transition, non-ARO P&A costs, and other miscellaneous costs as a percent of revenue, which is not a financial measurement under GAAP.

Although we have historically increased our reserves and production through acquisitions, our drilling program, and other projects that optimize production on existing wells, our production decreased 13% in 2023 from the prior year. Our proved reserves also decreased by 42.3 MMBoe in 2023, primarily due to the significant decrease in commodity prices in 2023 as compared to 2022.

We continually monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2024 plans. See *Liquidity and Capital Resources* under this Item 7 in this Form 10-K for additional information.

Recent Developments

On December 13, 2023, we 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 Mexico, among other assets, for a gross purchase price of $72.0 million, subject to customary purchase price adjustments. The transaction closed on January 16, 2024 and was funded using cash on hand. The Company also assumed the related AROs associated with these assets.

On February 28, 2024, we amended the Credit Agreement to extend the maturity date to March 28, 2024.

On March 5, 2024, we declared a first quarter dividend of $0.01 per share. We expect to pay the dividend on March 25, 2024, to stockholders of record as of the close of business on March 18, 2024.

Factors Affecting the Comparability of our Financial Condition and Results of Operations

In January 2023, we issued $275.0 million of 11.75% Notes. The 11.75% Notes were issued at par and have a maturity date of February 1, 2026. In February 2023, we redeemed all of the 9.75% Notes outstanding at a redemption price of 100.000%, plus accrued and unpaid interest to the redemption date. We used the net proceeds from the issuance of the 11.75% Notes and $296.1 million of cash on hand to fund the redemption. See *Financial Statements and Supplementary Data –Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information.

In September 2023, we acquired working interests in certain oil and natural gas producing assets in the central and eastern shelf region of the Gulf of Mexico for $27.4 million. This transaction is described in more detail under *Financial Statements and Supplementary Data – Note 7 – Acquisitions*, under Part II, Item 8 of this Annual Report.

Known Trends and Uncertainties

Volatility in Oil, NGL and Natural Gas Prices – Historically, the markets for oil and natural gas have been volatile. Our cash flows are materially impacted by the prices of commodities we produce (oil and natural gas, and the NGLs extracted from the natural gas). Our realized sales prices received for our oil, NGLs and natural gas production are affected by 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. For 2023, our realized prices for oil decreased 19%, NGLs decreased 38% and natural gas decreased 59% from 2022, having an adverse impact on our margins in addition to increased operating expenses. As a result, we cannot accurately predict future commodity prices, therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our drilling program, production volumes or revenues.

The U.S. Energy Information Administration (“EIA”) published its latest Short-Term Energy Outlook in February 2024. Spot prices for WTI oil averaged $77.58 per barrel in 2023, and the EIA is forecasting WTI spot prices to average $77.68 for 2024. The WTI oil spot price increased in January 2024 compared with the December 2023 average price of $71.89 per barrel, averaging $73.82 per barrel because of heightened uncertainty about global oil shipments as attacks to vessels in the Red Sea intensified. The EIA is forecasting WTI spot prices will rise into the mid-$80 per barrel range in the coming months, but downward pressures may emerge in 2024 as global oil inventories increase. Ongoing risks of supply disruptions in the Middle East could create the potential for oil prices to be higher than the EIA has forecasted.

Spot prices for Henry Hub natural gas averaged $2.53 per MMBtu in 2023, and the EIA is forecasting that Henry Hub prices will average $2.65 in 2024. The Henry Hub spot price averaged $3.23 per MMBtu in January 2024; however, spot prices were volatile, rising sharply to $13.20 per MMBtu on January 12 in anticipation of severely cold weather throughout the U.S. for the following weekend. After the weekend, prices quickly fell and continued to decrease until January 23, when the price hit the monthly low of $2.15 per MMBtu. Mild weather for the remainder of the first quarter of 2024 could keep the average Henry Hub spot price near $2.40 per MMBtu during February and March, but volatility could return if severely cold weather emerges, even for a short period.

We hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See *Financial Statements and Supplementary Data – Note 4 – Derivative Financial Instruments*, under Part II, Item 8 of this Annual Report for additional information regarding our commodity derivative positions as of December 31, 2023.

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 gas properties;
- reductions in our proved reserves and the estimated value thereof;
- additional supplemental bonding and potential collateral requirements;
- reductions in our borrowing base under the Credit Agreement; 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 described above.

Rising Interest Rates and Inflation of Cost of Goods, Services and Personnel – 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 increase, 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 in the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise.

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 2023 was 3.4%. These inflationary pressures have caused the Federal Reserve to tighten monetary policy by approving a series of increases to the Federal Funds Rate. As of December 31, 2023, the Federal Reserve benchmark rate ranged from 5.25% to 5.50%. Although the Federal Reserve has stated that they will begin reducing the benchmark rate in 2024, if inflation were to continue to rise, it is possible the Federal Reserve would continue to take action they deem necessary to bring inflation down and to ensure price stability, including further 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.

Inflation Reduction Act of 2022 – In August 2022, President Biden signed the IRA into law. Several provisions in the IRA are expected to apply to our business. For instance, the IRA specifically directs the DOI to accept the highest bids received for Lease Sale 257, which was vacated by U.S. District Court for the District of Columbia in January 2022, and move forward with Lease Sales 259 and 261 in the Gulf of Mexico, notwithstanding the June 30, 2022 expiration of the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program. Lease Sale 259 was held in March 2023, and Lease Sale 261 was held in December 2023.

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 Mexico scheduled in 2025, 2027 and 2029. In compliance with the IRA, these three lease sales are the minimum number that will enable the DOI to continue to expand its offshore wind leasing program through 2030. The reduction of the proposed OCS Program to a maximum of three potential lease sales will bring the federal oil and natural gas program in line with the Biden administration’s goal of net zero emissions by 2050 and meet the IRA’s requirement for future offshore renewable energy leasing.

The IRA also increases the minimum oil and gas royalty rate for new offshore leases from the current 12.50% to 16.67% and caps the royalty rate at 18.75% for 10 years. The 18.75% cap is commensurate with existing offshore royalty rate for leases in water depth exceeding 200 meters. This provision does not affect existing offshore leases.

Furthermore, the IRA amends the federal Clean Air Act to impose a fee on emissions of methane from sources required to report their greenhouse gas emissions to the EPA, including sources in the offshore and onshore oil and gas production, and onshore processing, transmission and compression, gathering, and boosting station source categories. For such qualifying facilities, the charge starts at $900 per metric ton of methane reported for calendar year 2024. In 2025, the charge increases to $1,200 per metric ton of methane. For calendar year 2026 and thereafter, the fee will be $1,500 per metric ton of methane. Calculation of the charge is based on certain thresholds established in the IRA. The charge will be based on the prior year's emissions, and the first fee payment will be in 2025 based on 2024 data. The methane emissions charge may increase our operating costs and adversely affect our business.

Impairment of Oil and Natural Gas Properties – Under the full cost method of accounting that we use for our oil and gas operations, our capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on our Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, NGL and natural gas prices may subsequently increase the ceiling. We perform this ceiling test calculation each quarter. In accordance with SEC rules and regulations, we utilize SEC pricing when performing the ceiling test. At December 31, 2023, our ceiling test computation was based on SEC pricing of $78.21 per Bbl of oil and $2.64 per Mcf of natural gas.

As part of our period end reserves estimation process for future periods, we expect changes in the key assumptions used, which could be significant, including updates to future pricing estimates and differentials, future production estimates to align with our anticipated five-year drilling plan and changes in our capital costs and operating expense assumptions. There is a significant degree of uncertainty with the assumptions used to estimate future undiscounted cash flows due to, but not limited to, the risk factors referred to in Part I, Item 1A. *Risk Factors*. Any decrease in pricing, negative change in price differentials, or increase in capital or operating costs could negatively impact the estimated undiscounted cash flows related to our proved oil and natural gas properties.

Deferred Production – Our oil, NGLs and natural gas production is 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, the transportation, gathering or processing of production and weather events. For 2023, we estimate deferred production was approximately 2,541 MBoe.

Regulations – We are subject to a number of regulations from federal and state governmental entities, which are described under Part I, Item 1. *Business – Environmental, Health and Safety Matters and Government Regulations* in this Form 10-K. We and others like us, are exposed to a number of risks by operating in the oil and natural gas industry in the Gulf of Mexico, which are described in Item 1A. *Risk Factors,* in this Form 10-K.

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. As of December 31, 2023, we are in compliance with our financial assurance obligations to the BOEM and have no outstanding BOEM orders related to financial assurance obligations. We and other offshore Gulf of Mexico producers may, in the ordinary course of business, receive demands in the future for financial assurances from the BOEM as the BOEM continues to reevaluate its requirements for financial assurance. 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.

Surety Bond Collateral – In prior years, some of the sureties that provide us surety bonds used for supplemental financial assurance purposes have requested and received collateral from us and may request additional collateral from us in the future, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety's discretion. In both 2023 and 2022, we have not had to post collateral for sureties, and we currently do not have any collateral posted for surety bonds. The issuance of any additional surety bonds or other security to satisfy future BOEM orders, collateral requests from surety bond providers and collateral requests from other third-parties may require the posting of cash collateral, which may be significant, and may require the creation of escrow accounts.

RESULTS OF OPERATIONS

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

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 our sources of revenue as a percentage of total revenue:

	Year Ended December 31,	
	2023	2022
Oil	71.6 %	56.9 %
NGLs	6.1 %	6.2 %
Natural gas	20.7 %	35.2 %
Other	1.6 %	1.7 %

The information below provides a discussion of, and an analysis of significant variance in, our oil, NGL and natural gas revenues, production volumes and average sales prices for 2023 and 2022 (in thousands):

	Year Ended December 31, 2023	Year Ended December 31, 2022	Change
Revenues:			
Oil	$ 381,389	$ 524,274	$ (142,885)
NGLs	32,446	56,964	(24,518)
Natural gas	110,158	323,831	(213,673)
Other	8,663	15,928	(7,265)
Total revenues	$ 532,656	$ 920,997	$ (388,341)
Production Volumes:			
Oil (MBbls)	5,050	5,602	(552)
NGLs (MBbls)	1,415	1,554	(139)
Natural gas (MMcf)	37,591	44,808	(7,217)
Total oil equivalent (MBoe)	12,730	14,624	(1,894)
Average daily equivalent sales (Boe/day)	34,877	40,067	(5,190)
Average realized sales prices:			
Oil ($/Bbl)	$ 75.52	$ 93.59	$ (18.07)
NGLs ($/Bbl)	22.93	36.66	(13.73)
Natural gas ($/Mcf)	2.93	7.23	(4.30)
Oil equivalent ($/Boe)	41.16	61.89	(20.73)
Oil equivalent ($/Boe), including realized commodity derivatives	40.84	59.15	(18.31)

Changes in average sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between 2023 and 2022 (in thousands):

	Price	Volume	Total
Oil	$ (91,250)	$ (51,635)	$ (142,885)
NGLs	(19,398)	(5,120)	(24,518)
Natural gas	(161,513)	(52,160)	(213,673)
	$ (272,161)	$ (108,915)	$ (381,076)

Realized Prices on the Sale of Oil, NGLs and Natural Gas – Our average realized sales price for oil differs from the WTI average spot price primarily due to premiums or discounts, quality adjustments, location adjustments and volume weighting (collectively referred to as differentials). Oil quality adjustments can vary significantly by field as a result of quality and location. All of our oil is produced offshore in the Gulf of Mexico and is primarily characterized as Poseidon, Light Louisiana Sweet and Heavy Louisiana Sweet. Similar to oil prices, the differentials for these types of oil can vary based on the aforementioned factors and have experienced volatility in the past.

Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. The changes in realized sales prices for NGLs are mostly a function of the change in oil prices combined with changes in supply and demand for propane and ethane.

The prices we realize for sales of natural gas differ from quoted Henry Hub spot prices as a result of quality and location differentials. During 2023, we experienced a positive natural gas differential due to approximately 70% of our natural gas being sold in a Florida market area, which had a premium to Henry Hub.

Oil, NGLs, and Natural Gas Volumes – Production volumes decreased by 1,894 MBoe to 12,730 MBoe during 2023 primarily due to downtime related to field and well maintenance events, primarily at Mobile Bay and other OCS fields, and natural production declines, partially offset by production from the acquisition completed in September 2023.

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, 2023	Year Ended December 31, 2022	Change
Operating expenses:			
Lease operating expenses	$ 257,676	$ 224,414	$ 33,262
Gathering, transportation and production taxes	26,250	35,128	(8,878)
Depreciation, depletion and amortization	114,677	107,122	7,555
Asset retirement obligations accretion expense	29,018	26,508	2,510
General and administrative expenses	75,541	73,747	1,794
Total operating expenses	$ 503,162	$ 466,919	$ 36,243
Average per Boe ($/Boe):			
Lease operating expenses	$ 20.24	$ 15.35	$ 4.89
Gathering, transportation and production taxes	2.06	2.40	(0.34)
Depreciation, depletion and amortization	9.01	7.33	1.68
Asset retirement obligations accretion expense	2.28	1.81	0.47
General and administrative expenses	5.93	5.04	0.89
Total operating expenses	$ 39.52	$ 31.93	$ 7.59

Lease operating expenses – Lease operating expenses include the expense of operating and maintaining our wells, platforms and other infrastructure primarily in the Gulf of Mexico. 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 $33.3 million to $257.7 million in 2023 compared to $224.4 million in 2022. On a per Boe basis, lease operating expenses increased to $20.24 per Boe during 2023 compared to $15.35 per Boe during 2022. On a component basis, base lease operating expenses increased $15.2 million, workover expenses increased $9.7 million and facility maintenance expenses increased $8.7 million. These increases were partially offset by a decrease of $0.3 million in hurricane repairs.

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 a full year of expenses at the fields acquired in February 2022 and three months of expenses at the fields acquired in September 2023, as well as higher repair, maintenance and labor costs at other fields. In addition, expenses related to our insurance coverage also increased due to higher premiums on our policies that were renewed in June 2023.

Workover and facility 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. During 2023, we incurred $12.0 million in workover expenses primarily at our Mobile Bay Properties due to numerous workover projects including well cleanout, recovering of fishing tools and stimulating to return the wells back to production.

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 and the Texas Department of Revenue on production of oil and natural gas from land or water bottoms within the boundaries of each state, respectively. Gathering, transportation and production taxes decreased to $26.3 million in 2023 compared to $35.1 million in 2022, primarily due to lower production volumes and realized prices partially offset by the transportation contract related to the properties acquired in 2022.

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. See Part II, Item 8. *Financial Statements and Supplementary Data — Note 1 — Summary of Significant Accounting Policies* for further discussion. DD&A increased to $114.7 million in 2023 from $107.1 million in 2022. The DD&A rate increased to $9.01 per Boe in 2023 from $7.33 per Boe in 2022. The DD&A rate per Boe increased primarily as a result of a higher depreciable base due to 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 $29.0 million in 2023 compared to $26.5 million in 2022 primarily due to the increase in our ARO liability (see Part II, Item 8. *Financial Statements and Supplementary Data — Note 8 — Asset Retirement Obligations*).

General and administrative expenses ("G&A") – G&A expense generally consists 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 2023, G&A expenses were $75.5 million compared to $73.7 million in 2022. The increase is primarily due to increased payroll costs, share-based compensation costs and professional fees, partially offset by a decrease in legal expenses and a $2.2 million employee retention credit recorded in 2023. Share-based compensation costs were higher due to the higher grant date fair values of share-based compensation awards outstanding during 2023 as compared to the value of awards outstanding during 2022. Legal expenses decreased primarily due to non-recurring legal fees incurred during 2022 related to a review of processes and controls within our information technology department.

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, 2023	Year Ended December 31, 2022	Change
Derivative (gain) loss, net	$ (54,759)	$ 85,533	$ (140,292)
Interest expense, net	44,689	69,441	(24,752)
Other expense, net	5,621	14,295	(8,674)
Income tax expense	18,345	53,660	(35,315)

Derivative (gain) loss – 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. During 2022, the $85.5 million derivative loss recorded for oil and natural gas derivative contracts consisted of $125.1 million of premium payments and realized losses on settled contracts and $39.6 million of unrealized gain, net from the increase in fair value of open contracts. During the second quarter of 2022, the Company monetized a portion of existing hedge positions through restructuring of strike prices on certain outstanding purchased calls covering the second half of 2022 through the first quarter of 2025. This transaction resulted in net cash proceeds of $105.3 million, which are included as an offset to realized losses for 2022.

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. 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. As of December 31, 2023, we do not have any open oil contracts. See *Financial Statements and Supplementary Data – Note 4 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense, net – Interest expense, net of interest income, was $44.7 million during 2023, decreasing $24.8 million from $69.4 million during 2022. The decrease is primarily due to the redemption of the 9.75% Notes in February 2023, decreased interest expense on the lower outstanding principal balance of the Term Loan and an increase in interest income, partially offset by interest expense incurred on the 11.75% Notes issued in late January 2023. See *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information on our debt.

Other expense, net – During 2023, other expense, net, was $5.6 million, compared to $14.3 million for 2022. During both 2023 and 2022, other expense primarily consisted of additional expenses for net abandonment obligations pertaining to a number of legacy Gulf of Mexico properties.

Income tax expense – Our effective tax rates for 2023 and 2022 were 54.0% and 18.8%, respectively. In 2023, the rate differed from the federal statutory rate of 21% primarily due to adjustments in the valuation allowance, compensation adjustments and the impact of state income taxes. In 2022, the rate differed from the federal statutory rate primarily due to adjustments in the valuation allowance and the impact of state income taxes.

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, 2023, we had $173.3 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.

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,		
	2023	**2022**	**Change**
Operating activities	$ 115,326	$ 339,530	$ (224,204)
Investing activities	(81,608)	(95,080)	13,472
Financing activities	(321,737)	(28,892)	(292,845)

Operating activities – Net cash provided by operating activities for 2023 was $115.3 million, decreasing $224.2 million from 2022. The change between periods is primarily due to (i) a $388.3 million decrease in revenues and (ii) a $36.2 million increase in operating expenses, partially offset by (iii) a $79.1 million decrease in derivative cash settlements, including premium payments, and (iv) a $29.0 million decrease in interest paid. These decreases in operating cash flow were partially offset by the changes in operating assets and liabilities which increased operating cash flows by $25.1 million primarily related to (i) lower accounts receivable balance due to decreased realized prices, (ii) and lower accounts payable and accrued liabilities balances in the current period and (iii) a $42.3 million decrease in ARO settlements.

Investing activities – Net cash used in investing activities for 2023 decreased $13.5 million compared to 2022. This was primarily due to decreases of $24.1 million in acquisition of property interests and $1.7 million in investment in oil and natural gas properties, partially offset by the purchase of the corporate aircraft and furniture, fixtures and other.

Financing activities – Net cash used in financing activities during 2023 increased by $292.8 million compared to 2022. This was primarily due to long-term debt repayments of $544.0 million, primarily due to the redemption of the $552.5 million principal amount outstanding 9.75% Notes and the $16.5 million of net proceeds received from the sales of equity securities under our at-the-market equity offering program in 2022, partially offset by the $275.0 million in proceeds from the issuance of the 11.75% Notes.

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,	
	2023	2022
Exploration [1]	$ 4,659	$ 13,339
Development [1]	35,356	20,390
Acquisitions of interests	27,384	51,474
Seismic and other	1,263	7,903
Investments in oil and gas property/equipment – accrual basis	$ 68,662	$ 93,106

(1) Reported geographically in the subsequent table.

The following table presents our exploration and development capital expenditures geographically (in thousands):

	Year Ended December 31,	
	2023	2022
Conventional shelf [1]	14,464	17,264
Deepwater	25,551	16,465
Exploration and development capital expenditures – accrual basis	$ 40,015	$ 33,729

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

Our preliminary capital expenditure budget for 2024 has been established in the range of $35.0 million to $45.0 million, which excludes acquisitions. In our view of the outlook for 2024, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2024 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 Mexico. We seek opportunities where we can exploit additional drilling projects and reduce costs. In September 2023, we acquired eight shallow water oil and natural gas producing assets in the central and eastern shelf region of the Gulf of Mexico for $27.4 million, after normal and customary post-effective date adjustments (including net operating cash flow attributable to the properties from the effective date to the respective closing date). The transaction was funded with cash on hand.

On December 13, 2023, we 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 Mexico, among other assets, for a gross purchase price of $72.0 million, subject to customary purchase price adjustments. The transaction closed on January 16, 2024 and was funded using cash on hand.

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

Annually, we review and revise our ARO estimates. Our ARO at December 31, 2023 and 2022 were $498.8 million and $466.4 million, respectively. The increase is primarily due to revisions in expected timing and amount of costs to be incurred. These increases were partially offset by $34.0 million related to liabilities settled during 2023. Our estimate of ARO spending in 2024 is approximately $35.0 to $45.0 million. During 2023 and 2022, we revised our estimates of costs anticipated to be charged by service providers for plugging and abandonment projects and revised our estimates to actual spending as invoices were processed and projects were completed. As these estimates are for work to be performed in the future, and in many cases, several years in the future, actual expenditures could be substantially different than our estimates. Additionally, we revise our estimates to account for the cost to comply with any new or revised regulations, including increases in work scope and cost changes from interpretation of work scope. See Part I, Item 1A. *Risk Factors* and *Financial Statements and Supplementary Data – Note 8 – Asset Retirement Obligations* under Part II, Item 8 in this Form 10-K for additional information regarding our ARO.

Debt

The primary terms of our long-term debt, the conditions related to incurring additional debt, and the conditions and limitations concerning early repayment of certain debt are disclosed in *Financial Statements and Supplementary Data –Note 2 – Debt* under Part II, Item 8 in this Form 10-K.

Term Loan – As of December 31, 2023, we had $114.2 million of Term Loan principal outstanding. The Term Loan requires quarterly amortization payments, bears interest at a fixed rate of 7.0% per annum and will mature on May 19, 2028. The Term Loan is non-recourse to us and our subsidiaries other than the Subsidiary Borrowers (and the subsidiary that owns the equity of the Subsidiary Borrowers) and is not secured by any assets other than first lien security interests in the equity in the Borrowers and a first lien mortgage security interest and mortgages on certain assets of the Subsidiary Borrowers.

11.75% Senior Second Lien Notes due 2026 – As of December 31, 2023, we had $275.0 million in aggregate principal amount of our 11.75% Notes issued and outstanding. The 11.75% Notes were issued at par with an interest rate of 11.75% per annum that matures on February 1, 2026. The 11.75% Senior Second Lien Notes are secured by second-priority liens on the same collateral that is secured under the Credit Agreement.

Credit Agreement – As of December 31, 2023, we had no borrowings outstanding under the Credit Agreement. On February 28, 2024, we amended the Credit Agreement to extend the maturity date to March 28, 2024.

TVPX Loan – As of December 31, 2023, we had $11.0 million of TVPX Loan principal outstanding. The TVPX Loan bears a fixed interest rate of 2.49% per annum 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.

Debt Covenants – The Term Loan, Credit Agreement and 11.75% Notes contain financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the respective Subsidiary Credit Agreement, the Credit Agreement and the indenture related to the 11.75% Notes. We were in compliance with all applicable covenants of the Term Loan, Credit Agreement and the 11.75% Notes indenture as of and for the period ended December 31, 2023.

Dividends

On November 8, 2023, we announced that our board of directors approved the implementation of a quarterly cash dividend payable to holders of common stock. The initial cash dividend of $0.01 per share of common stock, or $1.5 million, was paid on December 22, 2023, to shareholders of record at the close of business on November 28, 2023. 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.

Contractual Obligations and Commitments

Our material cash commitments from known contractual and other obligations consist primarily of obligations for long-term 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, 2023 are based on our estimates and assumptions about these obligations, including their duration, anticipated actions by third parties and other factors.

The following table summarizes our significant contractual obligations as of December 31, 2023 by maturity (in millions):

	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt – principal	$ 400.2	$ 31.2	$ 338.0	$ 31.0	$ —
Long-term debt – interest (1)	85.5	39.7	43.8	2.0	—
Operating leases	21.7	2.2	3.2	3.4	12.9
Asset retirement obligations (2)	498.8	31.6	64.4	87.8	315.0
Drilling rig commitment (3)	9.9	—	9.9	—	—
Other liabilities and commitments (4)	99.9	8.0	14.4	13.1	64.4
Total	$ 1,116.0	$ 112.7	$ 473.7	$ 137.3	$ 392.3

(1) Amounts represent the expected cash payments for interest based on the principal amounts outstanding and the stated interest rates and were calculated through the stated maturity date of the related debt.

(2) Amounts represent estimates of future payments and are presented on a discounted basis, consistent with the amount reported on our Consolidated Balance sheet. Actual payments and the timing of the payments may be significantly different than our estimates.

(3) During 2023, we entered into a contract for a drilling rig. The contract is to begin in February 2025 and terminate in October 2025.

(4) Other liabilities and commitments primarily consist of estimated fees for surety bonds related to obligations under certain purchase and sale agreements and for supplemental bonding for plugging and abandonment. As of December 31, 2023, we had approximately $454.2 million of bonds outstanding, with the majority related to plugging and abandonment obligations. 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, other liabilities and commitments include estimates of minimum quantities obligations for certain pipeline contracts which were assumed in conjunction with the purchase of an interest in the Heidelberg field. These amounts exclude our 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. These joint interest obligations for future commitments cannot be determined due to the variability of factors involved. See *Financial Statements and Supplementary Data – Note 17 – Commitments* under Part II, Item 8 in this 10-K for additional information.

THE SUBSIDIARY BORROWERS

During 2021, we formed A-I LLC and A-II LLC, both indirect, wholly-owned subsidiaries, through their parent, Aquasition Energy LLC (collectively, the "Aquasition Entities"). Concurrently, we designated the Aquasition Entities as unrestricted subsidiaries under the Indenture (the "Unrestricted Subsidiaries"). Having been so designated, the Unrestricted Subsidiaries do not guarantee the 11.75% Notes. The Unrestricted Subsidiaries are not bound by the covenants contained in the indenture related to our 11.75% Notes. Under the credit agreement the Aquasition Entities are party to (the "Subsidiary Credit Agreement") and related instruments, assets of the Aquasition Entities may not be available to mortgage or pledge as security to secure new indebtedness of us and our other subsidiaries. See *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information.

Below is consolidating balance sheet information reflecting the elimination of the accounts of our Unrestricted Subsidiaries from our Consolidated Balance Sheet as of December 31, 2023 (in thousands):

	Consolidated	Elimination of Unrestricted Subsidiaries	Restricted Subsidiaries
Assets			
Current assets:			
Cash and cash equivalents	$ 173,338	$ (600)	$ 172,738
Restricted cash	4,417	—	4,417
Receivables:			
Oil and natural gas sales	52,080	(19,171)	32,909
Joint interest, net	15,480	33,151	48,631
Other	2,218	—	2,218
Prepaid expenses and other current assets	17,447	(612)	16,835
Total current assets	264,980	12,768	277,748
Oil and natural gas properties and other, net	749,056	(287,313)	461,743
Restricted deposits for asset retirement obligations	22,272	—	22,272
Deferred income taxes	38,774	—	38,774
Other assets	38,923	(8,097)	30,826
Total assets	$ 1,114,005	$ (282,642)	$ 831,363
Liabilities and Shareholders' Equity (Deficit)			
Current liabilities:			
Accounts payable	$ 78,857	$ (4,473)	$ 74,384
Accrued liabilities	31,879	(7,152)	24,727
Undistributed oil and natural gas proceeds	42,134	(4,359)	37,775
Advances from joint interest partners	2,962	—	2,962
Income tax payable	99	—	99
Current portion of asset retirement obligation	31,553	(44)	31,509
Current portion of long-term debt, net	29,368	(28,872)	496
Total current liabilities	216,852	(44,900)	171,952
Asset retirement obligations, less current portion	467,262	(67,771)	399,491
Long-term debt, net	361,236	(82,317)	278,919
Deferred income taxes	51	—	51
Other liabilities	37,412	(6,749)	30,663
Shareholders' equity (deficit):			
Common stock	1	—	1
Additional paid-in capital	586,014	—	586,014
Retained deficit	(530,656)	(80,905)	(611,561)
Treasury stock, at cost	(24,167)	—	(24,167)
Total shareholders' equity (deficit)	31,192	(80,905)	(49,713)
Total liabilities and shareholders' equity (deficit)	$ 1,114,005	$ (282,642)	$ 831,363

Information reflecting the elimination of the accounts of our Unrestricted Subsidiaries from our Consolidated Statement of Operations for the year ended December 31, 2023 is as follows (in thousands):

	Consolidated	Elimination of Unrestricted Subsidiaries	Restricted Subsidiaries
Revenues:			
Oil	$ 381,389	$ (622)	$ 380,767
NGLs	32,446	(20,849)	11,597
Natural gas	110,158	(74,900)	35,258
Other	8,663	(4,506)	4,157
Total revenues	532,656	(100,877)	431,779
Operating expenses:			
Lease operating expenses	257,676	(79,824)	177,852
Gathering, transportation and production taxes	26,250	(8,169)	18,081
Depreciation, depletion, and amortization	114,677	3,383	118,060
Asset retirement obligations accretion	29,018	(5,980)	23,038
General and administrative expenses	75,541	(1,330)	74,211
Total operating expenses	503,162	(91,920)	411,242
Operating income	29,494	(8,957)	20,537
Interest expense, net	44,689	(10,400)	34,289
Derivative (gain) loss, net	(54,759)	71,724	16,965
Other expense, net	5,621	—	5,621
Income (loss) before income taxes	33,943	(70,281)	(36,338)
Income tax expense	18,345	—	18,345
Net income (loss)	$ 15,598	$ (70,281)	$ (54,683)

Produced oil, NGLs and natural gas volumes (net to our interests) from the Mobile Bay Properties are as follows:

	Year Ended December 31,	
Production Volumes:	**2023**	**2022**
Oil (MBbls)	15	17
NGLs (MBbls)	925	941
Natural gas (MMcf)	24,826	30,052
Total oil equivalent (MBoe)	5,078	5,967

Reserves information for the Mobile Bay properties is described in more detail under Part I, Item 2. *Properties,* in this Form 10-K.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our estimates on historical experience and other sources that we believe to be reasonable at the time. Changes in the facts and circumstances or the discovery of new information may result in revised estimates and actual results may vary from our estimates. Our significant accounting policies are detailed in *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Full Cost Accounting

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.

Capitalized costs associated with proved reserves are amortized over the life of the total proved reserves using the unit of production method, computed quarterly. Additionally, the amortizable base includes future development costs. The cost of unproved properties related to acquisitions are excluded from the amortization base until it is determined that proved reserves exist or until such time that impairment has occurred. We capitalize interest on unproved properties that are excluded from the amortization base. The costs of drilling non-commercial exploratory wells are included in the amortization base immediately upon determination that such wells are non-commercial. Under the full cost method, sales of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized unless an adjustment would significantly alter the relationship between capitalized costs and the value of proved reserves.

The computation of our DD&A rate includes estimates of reserves which requires significant judgment and is subject to change at each assessment. The determination of when proved reserves exist for our unproved properties requires judgment, which can affect our DD&A rate. Also, estimates of our capitalized ARO and estimates of future development costs require significant judgment. Actual results may be significantly different from such estimates, which would affect the timing of when these expenses would be recognized as DD&A. See *Oil and Natural Gas Reserve Quantities* and *Asset Retirement Obligations* below for more information.

Impairment of Oil and Natural Gas Properties

Under the full cost method, our capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash “Write-down of oil and natural gas properties” on the Consolidated Statements of Operations and an increase to “Accumulated depreciation, depletion and amortization” on the Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, NGL and natural gas prices may subsequently increase the ceiling. We perform this ceiling test calculation each quarter. In accordance with SEC rules and regulations, we utilize SEC pricing when performing the ceiling test. We also hold prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period. We did not have any ceiling test impairments in 2023, 2022 or 2021.

Oil and Natural Gas Reserve Quantities

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of DD&A and impairment assessment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of oil, NGL and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Our proved reserve information included in this Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The accuracy of our reserve estimates 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 and natural gas; and
- the judgments 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.

Asset Retirement Obligations

We have 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. We accrue a liability with respect to these obligations based on our estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with our asset retirement obligations, 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. Revisions to these estimates impact the value of our abandonment liability, our oil and natural gas property balance and our DD&A rates. After initial recording, the liability is increased for the passage of time, with the increase being reflected as “Accretion expense” in the Consolidated Statements of Operations. If we incur an amount different from the amount accrued for decommissioning obligations, we recognize the difference as an adjustment to our oil and natural gas properties.

Income Taxes

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

We apply significant judgment in evaluating tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact the Company’s financial position, results of operations and cash flows. We record adjustments to reflect actual taxes paid in the period that we complete our tax returns.

We account for uncertainty in income taxes recognized in the consolidated financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense. The final settlement of these tax positions may occur several years after the tax return is filed and may result in significant adjustments depending on the outcome of these settlements.

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, NGL 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 2023 and assuming no other items had changed, our revenue would have decreased by approximately $52.4 million in 2023. 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, costless collars, purchased calls, and purchased puts. Our derivatives will not mitigate all of 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,	
	2023	2022
Oil ($/Bbl):		
Average realized sales price, before the effects of derivative settlements	$ 75.52	$ 93.59
Effects of realized commodity derivatives	—	(12.35)
Average realized sales price, including realized commodity derivatives	$ 75.52	$ 81.24
Natural Gas ($/Mcf)		
Average realized sales price, before the effects of derivative settlements	$ 2.93	$ 7.23
Effects of realized commodity derivatives	(0.11)	0.65
Average realized sales price, including realized commodity derivatives	$ 2.82	$ 7.88

During 2023, our average realized natural gas price after the effect of derivatives decreased 64.2% during 2023 to $2.82 per Mcf from $7.88 per Mcf during 2022.

Interest Rate Risk

As of December 31, 2023, 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 Credit Agreement, we would be subject to some interest rate risk exposure, as our Credit Agreement has a variable interest rate which is primarily impacted by the rates for the Secured Overnight Financing Rate, and the current margin is 6.0% per annum. We do not have any derivative contracts related to interest rates as of December 31, 2023.

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, 2023 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, 2023 has been audited by Ernst & Young 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. and subsidiaries

Opinion on Internal Control over Financial Reporting

We have audited W&T Offshore, Inc. and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, W&T Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in shareholders' (deficit) equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and our report dated March 6, 2024 expressed an unqualified opinion thereon.

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/ Ernst & Young LLP

Houston, Texas
March 6, 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 sheets of W&T Offshore, Inc. and subsidiaries (the Company) as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in shareholders' (deficit) equity and cash flows for each of the three 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 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have 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, 2023, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 6, 2024 expressed an unqualified opinion thereon.

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 consolidated 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.

	Depreciation, Depletion and Amortization ("DD&A") of Oil and Natural Gas Properties
Description of the Matter	At December 31, 2023, the net book value of the Company's oil and natural gas properties was $718 million, and depreciation, depletion and amortization ("DD&A") expense was $113 million for the year then ended. As discussed in Note 1 to the consolidated financial statements, the Company follows the full-cost method of accounting for its oil and natural gas properties. Under this method, oil and natural gas properties included in the amortization base are amortized using the units-of-production method based on proved oil and natural gas reserves, as estimated by independent petroleum engineers. Proved oil and natural gas reserves are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Judgment is required by the independent petroleum engineers in interpreting the data used to estimate reserves. Estimating proved reserves also requires the selection of inputs, including historical production, oil and natural gas price assumptions, and future operating and capital costs assumptions, among others. Because of the complexity involved in estimating proved oil and natural gas reserves, management used independent petroleum engineers to prepare the oil and natural gas reserve estimates as of December 31, 2023. Auditing the Company's DD&A expense calculation is especially complex because of the use of the work of the independent petroleum engineers and the evaluation of the inputs described above used by the engineers in estimating proved oil and natural gas reserves.
How we Addressed the Matter in our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls that address the risks of material misstatement relating to the calculation of DD&A expense. This included management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved oil and natural gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent petroleum engineers used to prepare the oil and natural gas reserve estimates. On a sample basis, we tested the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved oil and natural gas reserves by agreeing them to source documentation, where available, and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. Additionally, we performed analytic and lookback procedures on select inputs into the oil and gas reserve estimate as well as on the outputs. Finally, we tested that the DD&A expense calculations are based on the appropriate proved oil and natural gas reserve balances from the Company's reserve report.
	Accounting for Asset Retirement Obligation
Description of the Matter	At December 31, 2023, the asset retirement obligation (ARO) balance totaled $499 million. As further described in Notes 1 and 8 to the consolidated financial statements, the Company records a liability for ARO in the period in which it is incurred, and a reasonable estimate can be made. The estimation of the ARO requires significant judgment given the magnitude of the expected retirement costs and higher estimation uncertainty related to the timing of settlements and settlement amounts.

	Auditing the Company's ARO is complex and required us to use significant judgment because of the estimation required by management in determining and measuring the expected cash outflows. In particular, the estimate was sensitive to significant subjective assumptions such as retirement cost estimates.
How we Addressed the Matter in our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligations. We also tested management's controls over the completeness and accuracy of financial data used in the valuation. Our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost estimates and timing of settlement assumptions. For example, we evaluated retirement cost estimates by comparing the Company's estimates to recent offshore activities and costs. Additionally, we compared assumptions for the timing of settlements to production forecasts.

/s/ Ernst & Young, LLP

We have served as the Company's auditor since 2000.

Houston, Texas
March 6, 2024

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

	December 31, 2023	December 31, 2022
Assets		
Current assets:		
Cash and cash equivalents	$ 173,338	$ 461,357
Restricted cash	4,417	4,417
Accounts receivable:		
Oil and natural gas sales	52,080	66,146
Joint interest, net	15,480	14,000
Other	2,218	—
Prepaid expenses and other current assets (Note 16)	17,447	24,343
Total current assets	264,980	570,263
Oil and natural gas properties and other, net (Note 1)	749,056	735,215
Restricted deposits for asset retirement obligations	22,272	21,483
Deferred income taxes	38,774	57,280
Other assets (Note 16)	38,923	47,549
Total assets	$ 1,114,005	$ 1,431,790
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 78,857	$ 65,158
Accrued liabilities (Note 16)	31,879	74,041
Undistributed oil and natural gas proceeds	42,134	41,934
Advances from joint interest partners	2,962	3,181
Income tax payable	99	412
Current portion of asset retirement obligation (Note 8)	31,553	25,359
Current portion of long-term debt, net (Note 2)	29,368	582,249
Total current liabilities	216,852	792,334
Asset retirement obligations (Note 8)	467,262	441,071
Long-term debt, net (Note 2)	361,236	111,188
Deferred income taxes	51	72
Other liabilities (Note 16)	19,369	59,134
Commitments and contingencies (Notes 17 and 19)	18,043	20,357
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000 shares authorized; none issued at December 31, 2023 and December 31, 2022	—	—
Common stock, $0.00001 par value; 400,000 shares authorized; 149,450 issued and 146,581 outstanding at December 31, 2023; 149,002 issued and 146,133 outstanding at December 31, 2022	1	1
Additional paid-in capital	586,014	576,588
Retained deficit	(530,656)	(544,788)
Treasury stock, at cost; 2,869 shares	(24,167)	(24,167)
Total shareholders' equity	31,192	7,634
Total liabilities and shareholders' equity	$ 1,114,005	$ 1,431,790

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,		
	2023	2022	2021
Revenues:			
Oil	$ 381,389	$ 524,274	$ 329,557
NGLs	32,446	56,964	44,343
Natural gas	110,158	323,831	173,749
Other	8,663	15,928	10,361
Total revenues	532,656	920,997	558,010
Operating expenses:			
Lease operating expenses	257,676	224,414	174,582
Gathering, transportation and production taxes	26,250	35,128	27,919
Depreciation, depletion, and amortization	114,677	107,122	90,522
Asset retirement obligations accretion	29,018	26,508	22,925
General and administrative expenses	75,541	73,747	52,400
Total operating expenses	503,162	466,919	368,348
Operating income	29,494	454,078	189,662
Interest expense, net	44,689	69,441	70,049
Derivative (gain) loss, net	(54,759)	85,533	175,313
Other expense (income), net	5,621	14,295	(6,165)
Income (loss) before income taxes	33,943	284,809	(49,535)
Income tax expense	18,345	53,660	(8,057)
Net income (loss)	$ 15,598	$ 231,149	$ (41,478)
Net income (loss) per common share:			
Basic	$ 0.11	$ 1.61	$ (0.29)
Diluted	0.11	1.59	(0.29)
Weighted average common shares outstanding:			
Basic	146,483	143,143	142,271
Diluted	148,302	145,090	142,271

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, 2020	142,305	$ 1	$ 550,339	$ (734,459)	2,869	$ (24,167)	$ (208,286)
Share-based compensation	—	—	3,364	—	—	—	3,364
Shares withheld related to net settlement of equity awards	—	—	(780)	—	—	—	(780)
Share-based compensation common stock issuances	558	—	—	—	—	—	—
Net loss	—	—	—	(41,478)	—	—	(41,478)
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

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2023	2022	2021
Operating activities:			
Net income (loss)	$ 15,598	$ 231,149	$ (41,478)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	143,695	133,630	113,447
Share-based compensation	10,383	7,922	3,364
Amortization and write off of debt issuance costs	6,980	7,551	6,555
Derivative (gain) loss	(54,759)	85,533	175,313
Derivative cash payments, net	(8,932)	(41,880)	(81,298)
Derivative cash premium payments	—	(46,111)	(40,484)
Deferred income taxes	18,485	45,184	(8,189)
Changes in operating assets and liabilities:			
Oil and natural gas receivables	14,066	(11,227)	(16,089)
Joint interest receivables	(1,480)	(4,255)	1,095
Prepaid expenses and other current assets	(2,712)	31,906	(5,103)
Accounts payable, accrued liabilities and other	10,722	(12,034)	46,099
Cash advances from JV partners	(219)	(11,892)	7,765
Income taxes	(2,531)	279	(20)
Asset retirement obligation settlements	(33,970)	(76,225)	(27,309)
Net cash provided by operating activities	115,326	339,530	133,668
Investing activities:			
Investment in oil and natural gas properties and equipment	(41,278)	(41,632)	(32,062)
Changes in operating assets and liabilities associated with investing activities	(535)	(1,894)	5,277
Acquisition of property interests	(27,384)	(51,474)	(661)
Purchase of corporate aircraft (Note 18)	(8,983)	—	—
Purchases of furniture, fixtures and other	(3,428)	(80)	2
Net cash used in investing activities	(81,608)	(95,080)	(27,444)
Financing activities:			
Repayment of 9.75% Senior Second Lien Notes due 2023	(552,460)	—	—
Repayment of Term Loan	(33,741)	(42,959)	(24,142)
Repayment of TVPX Loan	(733)	—	—
Repayment of Credit Facility	—	—	(80,000)
Proceeds from issuance of 11.75% Senior Second Lien Notes due 2026	275,000	—	—
Proceeds from issuance of Term Loan	—	—	215,000
Debt issuance costs	(7,380)	(1,675)	(9,810)
Net proceeds from issuance of common stock	—	16,458	—
Payment of dividends	(1,466)	—	—
Other	(957)	(716)	(782)
Net cash (used in) provided by financing activities	(321,737)	(28,892)	100,266
Change in cash, cash equivalents and restricted cash	(288,019)	215,558	206,490
Cash, cash equivalents and restricted cash, beginning of year	465,774	250,216	43,726
Cash, cash equivalents and restricted cash, end of year	$ 177,755	$ 465,774	$ 250,216

See accompanying 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 Mexico. The Company is active in the exploration, development and acquisition of oil and natural gas properties. Interests in fields, leases, structures and equipment are primarily owned by the Company and its 100% owned subsidiaries, W & T Energy VI, LLC, Aquasition LLC ("A-I LLC"), and Aquasition II, LLC ("A-II LLC"), and through a proportionately consolidated interest in Monza Energy LLC ("Monza"). 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 the proportionally consolidated interest in Monza. All significant intercompany accounts and transactions have been eliminated.

The accompanying consolidated financial statements have been prepared in accordance with U.S. GAAP and pursuant to the rules and regulations of the SEC for annual financial information.

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 (see *Note 2 — Debt*).

Revenue Recognition

The Company records revenues from the sale of oil, NGLs and natural gas based on quantities of production sold to purchasers under short-term contracts (less than twelve months) at market prices when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. Revenue from the sale of oil, NGLs and natural gas is recognized when performance obligations under the terms of the respective contracts are satisfied; this generally occurs with the delivery of oil, NGLs and natural gas to the customer. Each unit of product 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.

The Company recognizes revenue for all oil, NGL and natural gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. The Company does not record imbalance receivables for those properties in which the Company has taken less than its ownership share of production. As of December 31, 2023 and 2022, $3.7 million and $3.5 million, respectively, are reported in *Undistributed oil and natural gas proceeds* in the Consolidated Balance Sheets related to natural gas imbalances.

Concentration of Credit Risk

The Company's customers consist primarily of major oil and natural gas companies, well-established oil and pipeline companies and independent oil and gas producers and suppliers. The majority of the Company's production is sold to customers under short-term contracts at market-based prices. The Company attempts to minimize credit risk exposure to purchasers, joint interest owners, derivative counterparties and other third-party entities through formal credit policies, monitoring procedures, and letters of credit or guarantees when considered necessary.

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. In 2021, three customers accounted for 34%, 14% and 11%, 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.

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. 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.

The following table describes the balance and changes to the allowance for credit losses (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Allowance for credit losses, beginning of period	$ 12,062	$ 10,046	$ 9,123
Additional provisions for the year	123	3,085	2,192
Uncollectible accounts written off or collected	(1,055)	(1,069)	(1,269)
Allowance for credit losses, end of period	$ 11,130	$ 12,062	$ 10,046

Oil and Natural Gas Properties and Other, Net

The following table provides the components of *Oil and natural gas properties and other, net* (in thousands):

	December 31,	
	2023	2022
Oil and natural gas properties and related equipment	$ 8,919,403	$ 8,813,404
Furniture, fixtures and other	43,434	20,915
Total property and equipment	8,962,837	8,834,319
Less: Accumulated depreciation, depletion, amortization and impairment	(8,213,781)	(8,099,104)
Oil and natural gas properties and other, net	$ 749,056	$ 735,215

Oil and natural gas properties and equipment are recorded at cost using the full cost method. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and natural gas properties are capitalized. 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.

Oil and natural gas properties included in the amortization base are amortized using the units-of-production method based on production and estimates of proved reserve quantities. In addition to costs associated with evaluated properties and capitalized asset retirement obligations, the amortization base includes estimated future development costs to be incurred in developing proved reserves as well as estimated plugging and abandonment costs, net of salvage value, related to developing proved reserves. Future development costs related to proved reserves are not recorded as liabilities on the balance sheet but are part of the calculation of depletion expense.

Oil and natural gas properties and equipment will include costs of unproved properties when applicable. The cost of unproved properties related to significant acquisitions are excluded from the amortization base until the Company has made an evaluation that impairment has occurred. As of December 31, 2023 and 2022, the Company had no unproved properties. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are non-commercial.

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.

Furniture, fixtures and non-oil and natural gas property and equipment are depreciated 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.

Impairment of Oil and Natural Gas Properties and Other, Net

Under the full-cost method of accounting, the Company’s capitalized costs are limited to a quarterly ceiling test which determines a limit on the book value of oil and natural gas properties. If the net capitalized cost of oil and natural gas properties (including capitalized ARO) net of related deferred income taxes exceeds the ceiling test limit, the excess is charged to expense on a pre-tax basis and separately disclosed. Any such write downs are not recoverable or reversible in future periods.

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.

The Company did not record a ceiling test write-down during 2023, 2022 or 2021. If average oil and natural gas prices decrease below average pricing during 2024, the Company could incur ceiling test write-downs in future periods.

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.

Oil and Natural Gas Reserve Estimates

The Company utilizes SEC pricing when estimating quantities of proved reserves and the standardized measure of discounted future cash flows. Proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years, with some limited exceptions allowed. Refer to *Note 20 – Supplemental Oil and Gas Disclosures* for additional information.

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.

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.

After initial recording, the liability is increased for the passage of time, with the increase being reflected as *Accretion expense* on the Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for asset retirement obligations, the Company recognizes the difference as an adjustment to proved properties.

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. The Company may be held jointly and severally liable for the decommissioning of various facilities and related wells. The Company accrues losses associated with decommissioning obligations when such losses are probable and reasonably estimable. When there is a range of possible outcomes, the amount accrued is the most likely outcome within the range. If no single outcome within the range is more likely than the others, the minimum amount in the range is accrued. These accruals may be adjusted as additional information becomes available. In addition, when decommissioning obligations are reasonably possible, the Company discloses an estimate for a possible loss or range of loss (or a statement that such an estimate cannot be reasonably made). See *Note 19 — Contingencies* for additional information.

Derivative Financial Instruments

The Company uses commodity price derivative instruments to manage exposure to commodity price risk from sales of oil and natural gas. The Company does not enter into derivative instruments for speculative trading purposes.

Derivative instruments are recorded on the balance sheet as an asset or a liability at fair value. The Company does not designate derivatives instruments as hedging instruments, therefore, all changes in fair value are recognized in *Derivative (gain) loss* on the Consolidated Statement of Operations. See *Note 4 – Derivative Financial Instruments* for additional information.

Fair Value of Financial Instruments

Fair value information is included in the notes to the Consolidated Financial Statements when the fair value of the financial instruments is different from the book value or when it is required by U.S. GAAP. The carrying amount of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities approximates fair value due to the short-term, highly liquid nature of these instruments. See *Note 3 – Fair Value Measurements* for additional information.

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 U.S. 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 of the related tax benefits will not be realized.

During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. Such uncertain tax positions are recognized in the Consolidated Financial Statements when it is determined that the relevant tax authority would more likely than not sustain the position following an audit. Any interest and penalties related to uncertain tax positions are recorded in *Income tax expense*. See *Note 14 – Income Taxes* for additional information.

Debt Issuance Costs

Debt issuance costs associated with the Credit Agreement are amortized using the straight-line method over the scheduled maturity of the debt. The unamortized debt issue costs associated with the Credit Agreement are reported within *Prepaid expenses and other assets* in the Consolidated Balance Sheets.

Debt issuance costs associated with the Company's other long-term debt are amortized using the effective interest method over the scheduled maturity of the debt. The unamortized debt issuance costs associated with the current debt instruments are reported as a reduction to the carrying value of *Current portion of long-term debt, net* in the Consolidated Balance Sheet. Unamortized debt issuance costs associated with the long-term portion of debt instruments is reported as a reduction of the carrying value of *Long-term debt*, *net* in the Consolidated Balance Sheets.

Share-Based Compensation

Compensation cost for share-based payments to employees and non-employee directors is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which the recipient is required to provide service in exchange for the award. The fair value for equity instruments subject to only time or to Company performance measures was determined using the closing price of the Company's common stock at the date of grant. The fair value for equity instruments subject to market-based performance measures was determined using a Monte Carlo valuation model with estimates made as of the grant date. Share-based compensation expense is recognized over the period during which the recipient is required to provide service in exchange for the award. Estimates are made for forfeitures during the vesting period, resulting in the recognition of compensation cost only for those awards that are expected to vest, and estimated forfeitures are adjusted to actual forfeitures when the equity instrument vests. See *Note 12 – Share-Based Compensation* for additional information.

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 unvested restricted stock awards, restricted stock units and performance stock units when the effect is dilutive.

Accounting Standards to be Adopted

In December 2022, the Financial Accounting Standards Board issued Accounting Standards Update No. 2023-09, *Improvements to Income Tax Disclosures* ("ASU 2023-09") 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 is effective January 1, 2025 and should be applied prospectively, with retrospective application being permitted. 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.

No other new accounting pronouncements issued or effective during 2023 have had or are expected to have a material impact on the Company's consolidated financial statements.

NOTE 2 — DEBT

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

	December 31, 2023	December 31, 2022
Term Loan:		
Principal	$ 114,159	$ 147,899
Unamortized debt issuance costs	(3,052)	(4,592)
Total	111,107	143,307
Credit Agreement borrowings	—	—
11.75% Senior Second Lien Notes due 2026:		
Principal	275,000	—
Unamortized debt issuance costs	(5,090)	—
Total	269,910	—
TVPX Loan:		
Principal	11,025	—
Unamortized discount	(1,294)	—
Unamortized debt issuance costs	(144)	—
Total	9,587	—
9.75% Senior Second Lien Notes due 2023:		
Principal	—	552,460
Unamortized debt issuance costs	—	(2,330)
Total	—	550,130
Total debt, net	390,604	693,437
Less current portion, net	(29,368)	(582,249)
Long-term debt, net	$ 361,236	$ 111,188

Current Portion of Long-Term Debt, Net

As of December 31, 2023, the current portion of long-term debt of $29.4 million represented principal payments due within one year on the TVPX Loan and Term Loan (defined below), net of current unamortized debt issuance costs.

Maturities of Long-Term Debt

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

2024	$	31.2
2025		28.7
2026		309.3
2027		22.8
2028		8.2
Thereafter		—
Total	$	400.2

Term Loan

On May 19, 2021, A-I LLC and A-II LLC (collectively, the “Subsidiary Borrowers”), both indirect wholly owned subsidiaries of the Company, entered into a credit agreement (the “Subsidiary Credit Agreement”) providing for a $215.0 million term loan (the “Term Loan”).

At that time, in exchange for the net cash proceeds received by the Subsidiary Borrowers from the Term Loan, the Company assigned to (a) A-I LLC all of its interests in certain oil and gas leasehold interests and associated wells and units located in State of Alabama waters and U.S. federal waters in the offshore Gulf of Mexico, Mobile Bay region (such assets, the “Mobile Bay Properties”) and (b) A-II LLC its interest in certain gathering and processing assets located (i) in State of Alabama waters and U.S. federal waters in the offshore Gulf of Mexico, Mobile Bay region and (ii) onshore near Mobile, Alabama, including offshore gathering pipelines, an onshore oil treating and sweetening facility, an onshore gathering pipeline, and associated assets (such assets, the “Midstream Assets”).

The Term Loan requires quarterly amortization payments and bears interest at a fixed rate of 7.0% per annum. The Term Loan matures on May 19, 2028. The Subsidiary Credit Agreement also requires the Company to enter into certain natural gas swaps and put derivative instruments (see *Note 4 – Derivative Financial Instruments)*.

The Term Loan is non-recourse to the Company and any subsidiaries other than the Subsidiary Borrowers and the subsidiary that owns the equity in the Subsidiary Borrowers (the “Subsidiary Parent”), and is secured by the 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 (the Mobile Bay Properties, defined below). See *Note 5 – Subsidiary Borrowers* for additional information.

Credit Agreement

On November 2, 2021, the Company entered into the Ninth Amendment to the Sixth Amended and Restated Credit Agreement, which established a short-term $100.0 million first priority lien secured revolving facility with borrowings limited to a borrowing base of $50.0 million (the “Credit Agreement”) provided by Calculus Lending, LLC (“Calculus”), a company affiliated with and controlled by the Company’s CEO, as sole lender under the facility. Additionally, as of November 2, 2021, the Company cash collateralized each of the outstanding letters of credit in the aggregate amount of $4.4 million. Alter Domus (US) LLC was appointed to replace Toronto Dominion (Texas) LLC as administrative agent under the Credit Agreement.

On November 7, 2022, the Company entered into the Eleventh Amendment to the Credit Agreement, which extended the maturity date and Calculus’ commitment to January 3, 2024, and shifted the rate at which outstanding borrowings will accrue interest to a SOFR-based rate.

The Company has since entered into a series of amendments to extend the maturity date on the Credit Agreement, with the most recent being the Fifteenth Amendment to the Credit Agreement, dated as of February 28, 2024, to extend the maturity date from February 29, 2024, to March 28, 2024.

A committee of the independent members of the board of directors reviewed and approved each of these amendments given the CEO's affiliation with Calculus. See *Note 18 – Related Parties* for additional information.

As a result of the amendments noted above and related assignments and agreements the primary terms and covenants associated with the Credit Agreement as of December 31, 2023 are as follows:

- $100.0 million first priority lien secured revolving credit facility, with borrowings limited to a borrowing base of $50.0 million;
- Outstanding borrowings accrue interest at SOFR plus 6.0% per annum and the commitment fee for the unused portion of available borrowing capacity is 3.0% per annum;
- The Company's ratio of First Lien Debt (as such term is defined in the Credit Agreement) outstanding under the Credit Agreement on the last day of the most recent quarter to EBITDAX (as such term is defined in the Credit Agreement) for the trailing four quarters must not be greater than 2.50 to 1.00;
- The Company's ratio of Total Proved PV-10 to First Lien Debt (as such terms are defined in the Credit Agreement) as of the last day of any fiscal quarter must be equal to or greater than 2.00 to 1.00;
- The ratio of the Company and its restricted subsidiaries' consolidated current assets to consolidated current liabilities (subject in each case to certain exceptions and adjustments as set forth in the Credit Agreement) at the last day of any fiscal quarter must be greater than or equal to 1.00 to 1.00;
- As of the last day of any fiscal quarter, the Company and its restricted subsidiaries on a consolidated basis must pass a "Stress Test" to determine whether certain future net revenues from the Company's and its restricted subsidiaries' and certain joint ventures' oil and gas properties included in the collateral are sufficient to satisfy the aggregate first lien indebtedness under the Credit Agreement assuming the Borrowing Base is 100% funded or fully utilized; and
- Certain related party transactions are required to meet certain arm's length criteria; except in each case as specifically permitted or excluded from the covenant under the Credit Agreement.

Availability under the Credit Agreement is subject to redetermination of the borrowing base that may be requested at the discretion of either the lender or the Company in accordance with the Credit Agreement. Any redetermination by the lender to change the borrowing base will result in a similar change in the availability under the Credit Agreement. The borrowing base was reconfirmed at $50.0 million in October 2023. 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.

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

11.75% Senior Second Lien Notes due 2026

On January 27, 2023, the Company issued at par $275.0 million in aggregate principal amount of its 11.75% Senior Second Lien Notes (the "11.75% Notes") 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, which does not include the Mobile Bay Properties and the related Midstream Assets. The estimated annual effective interest rate on the 11.75% Notes is 12.6%, which includes amortization of debt issuance costs.

Prior to August 1, 2024, the Company may redeem all or any portion of the 11.75% Notes at a redemption price equal to 100% of the principal amount of the notes outstanding plus accrued and unpaid interest, if any, to the redemption date, plus the "Applicable Premium" (as defined in the Indenture). In addition, prior to August 1, 2024, the Company may, at its option, on one or more occasions redeem up to 35% of the aggregate original principal amount of the 11.75% Notes in an amount not greater than the net cash proceeds from certain equity offerings at a redemption price of 111.75% of the principal amount of the outstanding plus accrued and unpaid interest, if any, to the redemption date.

On and after August 1, 2024, 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% for the 12-month period beginning August 1, 2024, 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.

The 11.75% Notes contain covenants that limit or prohibit the Company's ability and the ability of certain of its subsidiaries to: (i) make investments; (ii) incur additional indebtedness or issue certain types of preferred stock; (iii) create certain liens; (iv) sell assets; (v) enter into agreements that restrict dividends or other payments from the Company's subsidiaries to the Company; (vi) consolidate, merge or transfer all or substantially all of the assets of the Company; (vii) engage in transactions with affiliates; (viii) pay dividends or make other distributions on capital stock or subordinated indebtedness; and (ix) create subsidiaries that would not be restricted by the covenants of the Indenture. These covenants are subject to important exceptions and qualifications set forth in the Indenture. In addition, most of the above-described covenants will terminate if both S&P Global Ratings, a division of S&P Global Inc., and Moody's Investors Service, Inc. assign the 11.75% Notes an investment grade rating and no default exists with respect to the 11.75% Notes.

TVPX Loan

On May 15, 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 18 – 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.

The TVPX Loan bears a fixed interest rate of 2.49% per annum 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. At the date of assumption, the Company determined that the fair market value of the TVPX Loan was $10.1 million using current market rates.

The aircraft was purchased as part of a series of transactions pursuant to which the Company restructured the compensation for its Named Executive Officers. Prior to the Company's purchase of the aircraft, the Company used the aircraft for business purposes, and the CEO also used the aircraft for personal purposes. Both the Company's use for business purposes and the CEO's use for personal purposes were paid for by the Company pursuant to the CEO's prior employment agreement. In connection with the Company's efforts to reduce overall executive compensation, including perquisite compensation Mr. Krohn was receiving for personal use of the aircraft, on April 20, 2023, the Company entered into an amendment to the employment agreement with the CEO which requires that the Company be reimbursed for personal use of the aircraft in accordance with the Company's aircraft use policy.

Redemption of 9.75% Senior Second Lien Notes due 2023

On February 8, 2023, the Company redeemed all of the $552.5 million of aggregate principal outstanding of the 9.75% Senior Second Lien Notes (the "9.75% Notes") at a redemption price of 100.0%, plus accrued and unpaid interest to the redemption date. The Company used the net proceeds from the issuance of the 11.75% Notes and cash on hand to fund the redemption.

Covenants

As of December 31, 2023 and for all presented measurement periods, the Company was in compliance with all applicable covenants of the Credit Agreement and the Indenture.

NOTE 3 — 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. The fair value of an asset should reflect its highest and best use by market participants, whether using an in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company's credit risk.

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. Inputs to valuation techniques are classified as either observable or unobservable within the following hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities.
- Level 2 – inputs other than quoted prices that are observable for an asset or liability. These include: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).
- Level 3 – unobservable inputs that reflect the Company's expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

Derivative Financial Instruments

The Company measures the fair value of derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. 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. Derivative financial instruments are reported in the Consolidated Balance Sheets using fair value. See *Note 4 – Derivative Financial Instruments* for additional information.

The following table presents the fair value of the Company's derivative financial instruments (in thousands):

	December 31, 2023	December 31, 2022
Assets:		
Derivative instruments - current	$ 1,180	$ 4,954
Derivative instruments - long-term	10,068	23,236
Liabilities:		
Derivative instruments - current	6,267	46,595
Derivative instruments - long-term	2,756	43,061

Debt Instruments

The fair values 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 and 9.75% Notes were measured using quoted prices, although the market is not a highly liquid market. The fair value of debt was classified as Level 2 within the valuation hierarchy. See *Note 2 – Debt* for additional information.

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

	December 31, 2023		December 31, 2022	
	Net Value	Fair Value	Net Value	Fair Value
TVPX Loan	$ 9,587	$ 10,156	$ —	$ —
Term Loan	111,107	108,467	143,307	139,056
11.75% Notes	269,910	283,443	—	—
9.75% Notes	—	—	550,130	544,902
Total	$ 390,604	$ 402,066	$ 693,437	$ 683,958

NOTE 4 — DERIVATIVE FINANCIAL INSTRUMENTS

The Company's market risk exposure relates primarily to commodity prices. The Company attempts to mitigate a portion of its commodity price risk and stabilize cash flows associated with sales of oil and natural gas production through the use of oil and natural gas swaps, costless collars, sold calls and purchased puts. 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.

The Company has elected not to designate commodity derivative contracts for hedge accounting. Accordingly, commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts, and changes in the unrealized fair value, recorded as *Derivative (gain) loss* on the Consolidated Statements of Operations in each period presented. The cash flows of all commodity derivative contracts are included in *Net cash provided by operating activities* on the Consolidated Statements of Cash Flows.

The Company's natural gas contracts are based off the Henry Hub price which is quoted off NYMEX.

The following table reflects the contracted volumes and weighted average prices under the terms of the Company's open natural gas derivative contracts as of December 31, 2023:

Period	Instrument Type	Average Daily Volumes	Total Volumes	Weighted Strike Price	Weighted Put Price	Weighted Call Price
Jan 2024 - Dec 2024	calls	65,000	23,790,000	$ —	$ —	$ 6.13
Jan 2025 - Mar 2025	calls	62,000	5,580,000	$ —	$ —	$ 5.50
Jan 2024 - Dec 2024 [1]	swaps	65,576	24,000,000	$ 2.46	$ —	$ —
Jan 2025 - Mar 2025 [1]	swaps	63,333	5,700,000	$ 2.72	$ —	$ —
Apr 2025 - Dec 2025 [1]	puts	62,183	17,100,000	$ —	$ 2.27	$ —
Jan 2026 - Dec 2026 [1]	puts	55,895	20,400,000	$ —	$ 2.35	$ —
Jan 2027 - Dec 2027 [1]	puts	52,607	19,200,000	$ —	$ 2.37	$ —
Jan 2028 - Apr 2028 [1]	puts	49,725	6,000,000	$ —	$ 2.42	$ —

(1) These contracts were entered into by the Company's wholly owned subsidiary, A-I LLC.

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

	December 31,	
	2023	2022
Prepaid expenses and other current assets	$ 1,180	$ 4,954
Other assets	10,068	23,236
Accrued liabilities	6,267	46,595
Other liabilities	2,756	43,061

Although the Company has master netting arrangements with its counterparties, the amounts recorded on the Consolidated Balance Sheets are on a gross basis.

Changes in the fair value and settlements of contracts are recorded on the Consolidated Statements of Operations as *Derivative (gain) loss*. The impact of commodity derivative contracts on the Consolidated Statements of Operations was as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Realized loss	$ 4,087	$ 125,089	$ 95,187
Unrealized (gain) loss	(58,846)	(39,556)	80,126
Derivative (gain) loss, net	(54,759)	85,533	175,313

NOTE 5 — SUBSIDIARY BORROWERS

The Subsidiary Borrowers used the net proceeds of the Term Loan (see *Note 2 – Debt)* to (i) fund the acquisition of the Mobile Bay Properties and the Midstream Assets from the Company and (ii) pay fees, commissions and expenses in connection with the transactions contemplated by the Subsidiary Credit Agreement and the other related loan documents, including to enter into certain swap and put derivative contracts described in more detail under *Note 4 – Derivative Financial Instruments*, of this Annual Report.

As part of the transaction, the Subsidiary Borrowers entered into a management services agreement (the "Services Agreement") with the Company, pursuant to which the Company will provide (a) certain operational and management services for the Mobile Bay Properties and the Midstream Assets and (b) certain corporate, general and administrative services for the Subsidiary Borrowers (collectively in this capacity, the "Services Recipient"). Under the Services Agreement, the Company will indemnify the Services Recipient with respect to claims, losses or liabilities incurred by the Services Agreement Parties that relate to personal injury or death or property damage of the Company, in each case, arising out of performance of the Services Agreement, except to the extent of the gross negligence or willful misconduct of the Services Recipient. The Services Recipient will indemnify the Company with respect to claims, losses or liabilities incurred by the Company that relate to personal injury or death of the Services Recipient or property damage of the Services Recipient, in each case, arising out of performance of the Services Agreement, except to the extent of the gross negligence or willful misconduct of the Company. The Services Agreement will terminate upon the earlier of (a) termination of the Subsidiary Credit Agreement and payment and satisfaction of all obligations thereunder or (b) the exercise of certain remedies by the secured parties under the Subsidiary Credit Agreement and the realization by such secured parties upon any of the collateral under the Subsidiary Credit Agreement.

The Subsidiary Borrowers are wholly-owned subsidiaries of the Company; however, the assets of the Subsidiary Borrowers are not available to satisfy the debt or contractual obligations of any other entities, including debt securities or other contractual obligations of the Company, and the Subsidiary Borrowers do not bear any liability for the indebtedness or other contractual obligations of any other entities, and vice versa.

During 2023, the Subsidiary Borrowers did not pay any cash distributions to the Company. During 2022, the Subsidiary Borrowers paid cash distributions of $30.2 million to the Company.

Consolidation and Carrying Amounts

The following table presents the amounts recorded by the Company on the Consolidated Balance Sheets related to the consolidation of the Subsidiary Borrowers and the Subsidiary Parent (in thousands):

	December 31,	
	2023	**2022**
Assets:		
Cash and cash equivalents	$ 600	$ 21,764
Receivables:		
Oil and natural gas sales	19,171	37,344
Joint interest, net	(33,151)	(5,760)
Prepaid expenses and other assets	612	417
Oil and natural gas properties and other, net	287,313	280,649
Other assets	8,097	8,473
Liabilities:		
Accounts payable	4,473	27,387
Accrued liabilities	7,152	45,102
Undistributed oil and natural gas proceeds	4,359	7,930
Current portion of long-term debt, net	28,872	32,119
Asset retirement obligations	67,771	61,138
Long-term debt, net	82,317	111,188
Other liabilities	6,749	47,398

The following table presents the amounts recorded by the Company in the Consolidated Statement of Operations related to the consolidation of the operations of the Subsidiary Borrowers and the Subsidiary Parent (in thousands):

	Year Ended December 31,	
	2023	**2022**
Total revenues	$ 100,877	$ 268,573
Total operating expenses	91,920	73,990
Interest expense, net	10,400	14,721
Derivative (gain) loss	(71,724)	141,736

NOTE 6 — JOINT VENTURE DRILLING PROGRAM

During 2018, the Company and other members formed and funded Monza, which jointly participates with the Company in the exploration, drilling and development of certain drilling projects (the “Joint Venture Drilling Program”) in the Gulf of Mexico. The total commitments by all members, including the Company’s commitment to fund its retained interest in Monza projects held outside of Monza, were $361.4 million. The Company contributed 88.94% of its working interest in certain identified undeveloped drilling projects to Monza and retained 11.06% of its working interest. 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.

The members of Monza are third-party investors, the Company and an entity owned and controlled by the Company’s CEO. The entity affiliated with the Company’s CEO invested as a minority investor on the same terms and conditions as the third-party investors. Its investment is limited to 4.5% of total invested capital within Monza and it made a capital commitment to Monza of $14.5 million.

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, 2023, ten wells have been completed since the inception of the Joint Venture Drilling Program, and the Company is the operator for eight of these wells completed.

Since inception through December 31, 2023, 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 $214.9 million. Since inception through December 31, 2023, 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 $46.4 million.

Consolidation and Carrying Amounts

Monza is considered a variable interest entity that is proportionally consolidated. Through December 31, 2023, there have been no events or changes that would cause a redetermination of the variable interest status. The Company does not fully consolidate Monza because the Company is not considered the primary beneficiary of Monza.

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

	December 31,	
	2023	2022
Working capital	$ 1,159	$ 2,515
Oil and natural gas properties and other, net	31,805	37,260
Asset retirement obligations	593	467
Other assets	11,694	11,571

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, 2023 and 2022, the unused advances were $2.7 million and $2.9 million, respectively, which are included in *Advances from joint interest parties* in the Consolidated Balance Sheets.

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,	
	2023	2022
Total revenues	$ 13,086	$ 28,803
Total operating expenses	9,436	13,523
Interest income	199	42

NOTE 7 — ACQUISITIONS

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 Mexico 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.

On January 5, 2022, the Company entered into a purchase and sale agreement with ANKOR E&P Holdings Corporation and KOA Energy LP to acquire their interests in and operatorship of certain oil and natural gas producing properties in federal shallow waters in the Gulf of Mexico at Ship Shoal 230, South Marsh Island 27/Vermilion 191, and South Marsh Island 73 fields for $47.0 million. The transaction closed on February 1, 2022, and after normal and customary post-effective date adjustments (including net operating cash flow attributable to the properties from the effective date of July 1, 2021 to the close date), cash consideration of $34.0 million was paid to the sellers. The transaction was funded using cash on hand. The Company also assumed the related AROs associated with these assets.

Additionally, on April 1, 2022, the Company entered into a purchase and sale agreement with a private seller to acquire the remaining working interests in certain oil and natural gas producing properties in federal shallow waters of the Gulf of Mexico at the Ship Shoal 230, South Marsh Island 27/Vermilion 191, and South Marsh Island 73 fields. The transaction had an effective date and closing date of April 1, 2022. After normal and customary post-effective date adjustments, cash consideration of $17.5 million was paid to the seller.

The Company determined that the assets acquired did not meet the definition of a business; therefore, these transactions were accounted for as asset acquisitions. An acquisition qualifying as an asset acquisition requires, among other items, that the cost of the assets acquired and liabilities assumed to be recognized on the Consolidated Balance Sheet by allocating the asset cost on a relative fair value basis. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations 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 amounts recorded on the Consolidated Balance Sheet for the purchase price allocation and liabilities assumed related to the acquisitions described above are presented in the following tables (in thousands):

	September 2023
Oil and natural gas properties and other, net	$ 43,736
Asset retirement obligations	(16,352)
Allocated purchase price	$ 27,384

	February 2022
Oil and natural gas properties and other, net	$ 54,299
Restricted deposits for asset retirement obligations	6,196
Asset retirement obligations	(26,493)
Allocated purchase price	$ 34,002

	April 2022
Oil and natural gas properties and other, net	$ 22,632
Restricted deposits for asset retirement obligations	1,549
Asset retirement obligations	(6,709)
Allocated purchase price	$ 17,472

NOTE 8 — ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations associated with the retirement and decommissioning of tangible long-lived assets are required to be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The fair value of the ARO is measured using expected cash outflows associated with the ARO, discounted at the Company's credit-adjusted risk-free rate when the liability is initially recorded. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

The following changes in liability are included in the Consolidated Balance Sheet in current and long-term liabilities, and the changes in that liability were as follows (in thousands):

	Year Ended December 31,	
	2023	2022
Asset retirement obligations, beginning of period	$ 466,430	$ 424,495
Liabilities settled	(33,970)	(76,225)
Accretion expense	29,018	26,508
Liabilities acquired	16,352	33,202
Liabilities incurred	129	138
Revisions of estimated liabilities	20,856	58,312
Asset retirement obligations, end of period	498,815	466,430
Less: Current portion	(31,553)	(25,359)
Long-term	$ 467,262	$ 441,071

NOTE 9 — RESTRICTED DEPOSITS FOR ARO

Restricted deposits for ARO consist of funds escrowed for collateral related to the future plugging and abandonment obligations of certain oil and natural gas properties. These deposits relate to the following fields (in thousands):

	December 31,	
	2023	2022
Main Pass 283/Viosca Knoll 734 (1)	$ 13,887	$ 13,684
South Marsh Island 73 (2)	7,756	7,753
Other	629	46

(1) In connection with the acquisition of these fields, the Company received funds from the previous operator to cover future asset retirement obligations for those fields. The Company is not obligated to contribute additional amounts to these escrowed accounts.

(2) In connection with the acquisitions completed in 2022, the Company received funds from the previous owners to cover future asset retirement obligations. The Company is not obligated to contribute additional amounts to this escrowed account. See *Note 7 - Acquisitions* for additional information.

NOTE 10 — 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 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

On November 8, 2023, the Company announced that its board of directors approved the implementation of a quarterly cash dividend payable to holders of its common stock. The initial cash dividend of $0.01 per share of common stock, or $1.5 million, was paid on December 22, 2023, to shareholders of record at the close of business on November 28, 2023.

NOTE 11 — LEASES

The Company has operating leases consisting of an office lease, a hangar lease, a land lease and various pipeline right-of-way contracts. For these contracts, a right-of-use (“ROU”) asset and lease liability was established based on the Company’s assumptions of the term and incremental borrowing rates. At inception, contracts are reviewed to determine whether the agreement contains a lease. To the extent an arrangement is determined to include a lease, it is classified as either an operating or a finance lease, which dictates the pattern of expense recognition in the income statement.

The term of the office lease extends to February 2032 and has the option to extend, at the Company’s discretion, for up to an additional ten years. The term of the hangar lease extends to February 2025 and has the option to renew, at the Company’s discretion, for an additional two years. However, the Company is not reasonably certain that it will exercise any of the options to extend these leases and as such, they have not been included in the remaining lease terms. The term of each pipeline right-of-way contract is ten years with various effective dates, and each has an option to extend, at the Company’s discretion, for up to another ten years. It is expected renewals beyond ten years can be obtained as renewals were granted to the previous lessees. The land lease has an option to renew every five years extending to 2085. The expected term of the rights-of way and land leases was estimated to approximate the life of the related reserves. The expected term of the rights-of way and land leases was estimated to approximate the life of the related reserves at the inception of the lease.

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,		
	2023	2022	2021
Operating lease costs, excluding short-term leases	$ 1,670	$ 1,579	$ 1,743
Short-term lease cost [1]	58	2,957	5,926
Variable lease cost [2]	765	647	—
Total lease cost	$ 2,493	$ 5,183	$ 7,669

(1) Short-term lease costs are reported at gross amounts and primarily represent costs incurred for drilling rigs, most of which are short-term contracts not recognized as a right-of-use asset and lease liability on the balance sheet. The majority of such costs are recorded within “Oil and natural gas properties, net” in the consolidated balance sheet.

(2) 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, 2023	December 31, 2022
ROU assets − Other assets	$ 10,515	$ 10,364
Lease liability:		
Accrued liabilities	$ 1,455	$ 1,628
Other liabilities	10,803	10,527
Total lease liability	$ 12,258	$ 12,155

The table below presents the weighted average remaining lease term and discount rate related to leases (in thousands):

	December 31, 2023	2022	2021
Weighted average remaining lease term:	12.1 years	13.1 years	14.1 years
Weighted average discount rate:	10.3 %	10.1 %	10.1 %

The table below presents the supplemental cash flow information related to leases (in thousands):

	December 31, 2023	2022	2021
Operating cash outflow from operating leases	$ 1,713	$ 1,224	$ 425
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 559	$ —	$ —

Undiscounted future minimum payments as of December 31, 2023 are as follows (in thousands):

2024	$ 2,156
2025	1,601
2026	1,625
2027	1,658
2028	1,712
Thereafter	12,888
Total lease payments	21,640
Less: imputed interest	(9,382)
Total	$ 12,258

NOTE 12 — SHARE-BASED COMPENSATION

On June 16, 2023, the 2023 Incentive Compensation Plan (the "2023 Plan") was approved by the Company's shareholders. The Company will no longer grant awards pursuant to the W&T Offshore, Inc. Amended and Restated Compensation Plan, as amended from time to time, (the "Prior Incentive Plan") or the 2004 Directors Compensation Plan of W&T Offshore, Inc., as amended from time to time (the "Prior Director Plan"). The 2023 Plan covers the Company's eligible employees, non-employee directors and consultants and includes both cash and share-based compensation awards. The 2023 Plan grants the Compensation Committee of the board of directors administrative authority over all participants and grants the CEO with authority over the administration of awards granted to participants that are not subject to section 16 of the Exchange Act (as applicable, the "Compensation Committee"). Any awards granted prior to the effective date of the 2023 Plan are considered to have been granted under the applicable Prior Plan.

Pursuant to the terms of the 2023 Plan, the Compensation Committee establishes the vesting or performance criteria applicable to the award and may use a single measure or combination of business measures as described in the 2023 Plan. Also, individual goals may be established by the Compensation Committee. Performance awards may be granted in the form of stock options, stock appreciation rights, restricted stock (“RSAs”), 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. The performance awards granted under the 2023 Plan can be measured over a performance period of up to 10 years and annual incentive awards (a type of performance award) will generally be paid within 90 days following the applicable year end.

The Company has the option following vesting to settle RSUs and PSUs by either the issuance of common stock, cash or a combination thereof based on the fair market value of the common stock on the date of vesting. During 2023, 2022 and 2021, only shares of common stock were used to settle all vested RSUs and PSUs. The Company expects to settle RSUs and PSUs that vest in the future using shares of common stock.

As of December 31, 2023, the maximum number of shares of common stock available for issuance under the 2023 Plan is 10.0 million shares and 9.5 million shares remain available for grant. Shares subject to awards granted under the 2023 Plan that are subsequently canceled, forfeited or otherwise terminated without delivery of shares are available for future grant under the 2023 Plan. The Company’s policy is to issue new shares when RSAs are granted and RSUs and PSUs are vested.

Restricted Stock Units

During 2023, the Company granted RSUs to employees and non-employee directors under both the 2023 Plan and the Prior Incentive Plan. RSUs granted to employees are a long-term compensation component, subject to service conditions, and vest ratably over an approximate three-year period. The RSUs granted to non-employee directors under the 2023 Plan vest one year from the date of the grant or on the date of the Company’s annual shareholder meeting, subject to certain conditions.

Compensation cost for share-based payments to employees is recognized ratably 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 using the Company’s closing price on the grant date. 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 awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restricted period.

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	1,221,461	$ 5.76
Granted	1,813,522	4.06
Vested	(492,453)	5.62
Forfeited	(134,334)	5.50
Nonvested, end of period	2,408,196	4.52

The grant date fair value of RSUs granted during 2023, 2022 and 2021 was $7.4 million, $6.1 million and $3.3 million, respectively. The fair value of the RSUs that vested during 2023, 2022 and 2021 was $2.5 million, $1.9 million and $2.4 million, respectively, based on the closing price of the Company’s common stock on the vesting date.

As of December 31, 2023, there was $4.7 million of total unrecognized compensation costs related to unvested RSUs which is expected to be recognized over a weighted average period of 2.1 years.

Performance Share Units

During 2023, the Company granted PSUs to employees under both the 2023 Plan and the Prior Incentive Plan. PSUs are a long-term compensation component granted to certain employees. The PSUs are RSU awards granted subject to performance criteria. The performance criteria 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.

PSUs granted to employees in 2023 and 2022 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. PSUs granted in 2021 were subject to an approximate one-year performance period which ended on December 31, 2021. Subsequent to the performance period, the PSUs were subject to service-based criteria until the PSUs vested on September 29, 2023.

Compensation cost for share-based payments to employees is recognized ratably 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. All PSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restricted period. The grant date fair value of the 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 following table summarizes the assumptions used to calculate the grant date fair value of the PSUs granted during 2023:

Expected term for performance period (in years)	2.6
Expected volatility	76.1 %
Risk-free interest rate	4.2 %

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	1,502,239	$ 9.78
Granted	1,293,113	4.85
Vested	(151,812)	5.78
Forfeited	(244,821)	9.76
Nonvested, end of period	2,398,719	7.38

The grant date fair value of PSUs granted during 2023, 2022 and 2021 was $6.3 million, $14.2 million and $2.2 million, respectively. 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. No PSUs vested during 2021.

As of December 31, 2023, there was $8.7 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.

Restricted Stock

Under the Prior Director Plan, the Company granted RSAs to its non-employee directors in 2022 and 2021 as a component of their compensation arrangement. Vesting occurs upon completion of the one-year vesting period. The holders of RSAs generally have the same rights as a shareholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. RSAs are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restriction period.

A summary of activity related to RSAs is as follows:

	Restricted Shares	Weighted Average Grant Date Fair Value per Share
Nonvested, beginning of period	42,426	$ 4.95
Granted	—	—
Vested	(42,426)	4.95
Nonvested, end of period	—	—

The grant date fair value of RSAs granted during both 2022 and 2021 was $0.2 million and $0.2 million, respectively. The fair value of the RSAs that vested during 2023, 2022 and 2021 was $0.2 million, $0.4 million and $0.5 million, respectively, based on the closing price of the Company's common stock on the vesting date.

Share-Based Compensation Expense

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,		
	2023	2022	2021
Restricted stock units	$ 4,477	$ 4,192	$ 2,579
Performance share units	5,836	3,504	412
Restricted shares	70	226	373
Total	$ 10,383	$ 7,922	$ 3,364

NOTE 13 — EMPLOYEE BENEFIT PLAN

The Company maintains a defined contribution benefit plan (the "401(k) Plan") in compliance with Section 401(k) of the Internal Revenue Code ("IRC"), which covers those employees who meet the 401(k) Plan's eligibility requirements. During 2023, 2022 and 2021 the time periods where matching occurred, the Company's matching contribution was 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 $2.9 million, $2.4 million, and $2.0 million for 2023, 2022 and 2021, respectively.

NOTE 14 — INCOME TAXES

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2023	2022	2021
Current	$ (140)	$ 8,476	$ 132
Deferred	18,485	45,184	(8,189)
Total income tax expense (benefit)	$ 18,345	$ 53,660	$ (8,057)

Reconciliation

The Company's income tax expense (benefit) for 2023, 2022 and 2021 resulted in effective tax rates of 54.0%, 18.8% and (16.3)%, 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,		
	2023	2022	2021
Income tax expense (benefit) at the federal statutory rate	$ 7,128	$ 59,810	$ (10,402)
Compensation adjustments	1,752	599	559
State income taxes	1,143	2,418	(330)
Valuation allowance	8,125	(9,117)	1,863
Other	197	(50)	253
Total income tax expense (benefit)	$ 18,345	$ 53,660	$ (8,057)

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

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,	
	2023	2022
Deferred tax assets:		
Derivatives	$ 8,532	$ 25,969
Asset retirement obligations	109,111	103,910
Contingent asset retirement obligations	3,952	4,540
Right of use liability	2,895	2,964
Federal net operating losses	6,211	281
State net operating losses	5,941	5,691
Interest expense limitation carryover	17,501	9,620
Share-based compensation	2,262	1,546
Other	4,266	5,513
Total deferred tax asset	160,671	160,034
Valuation allowance	(23,202)	(15,311)
Total deferred tax asset after valuation allowance	137,469	144,723
Deferred tax liabilities:		
Property and equipment	$ 92,707	$ 80,616
Investment in non-consolidated entity	2,993	3,951
Other	3,046	2,948
Total deferred tax liabilities	98,746	87,515
Net deferred tax asset	$ 38,723	$ 57,208

Valuation Allowance

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

	Year Ended December 31,		
	2023	2022	2021
Balance at beginning of period	$ (15,311)	$ (24,359)	$ (22,361)
Additions to valuation allowance	(7,891)	—	(1,998)
Reductions to valuation allowance	—	9,048	—
Balance at end of period	$ (23,202)	$ (15,311)	$ (24,359)

Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on the Company's deferred tax assets, the Company considers whether it is more likely than not that some portion or all of them will not be realized.

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. Assumptions about the Company's future taxable income are consistent with the plans and estimates used to manage the Company's business. The Company showed positive income in 2023 and continues to project similar results into the future. Based on this, the Company concluded that there is enough positive evidence to outweigh any negative evidence although any changes in forecasted taxable income could have a material impact on this analysis. The portion of the valuation allowance remaining relates to state net operating losses and the disallowed interest limitation carryover under IRC section 163(j).

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, 2023 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 29,578	N/A
State net operating loss	100,903	2026-2042
Interest expense limitation carryover	79,914	N/A

Years Open to Examination

As of December 31, 2023, the tax years 2020 through 2023 remain open to examination by the federal and state tax jurisdictions where the Company conducts its business.

NOTE 15 — EARNINGS PER SHARE

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

	Year Ended December 31,		
	2023	2022	2021
Net income (loss)	$ 15,598	$ 231,149	$ (41,478)
Weighted average common shares outstanding - basic	146,483	143,143	142,271
Dilutive effect of securities	1,819	1,947	—
Weighted average common shares outstanding - diluted	148,302	145,090	142,271
Earnings per common share:			
Basic	$ 0.11	$ 1.61	$ (0.29)
Diluted	$ 0.11	$ 1.59	$ (0.29)
Shares excluded due to being anti-dilutive	—	—	1,370

NOTE 16 — OTHER SUPPLEMENTAL INFORMATION

Consolidated Balance Sheet Details

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

	December 31,	
	2023	2022
Derivatives [1]	$ 1,180	$ 4,954
Insurance/bond premiums	6,631	6,046
Prepaid deposits related to royalties	7,872	9,139
Prepayments to vendors	1,492	1,767
Prepayments to joint interest partners	117	1,717
Current portion of debt issuance costs	81	687
Other	74	33
Prepaid expenses and other current assets	$ 17,447	$ 24,343

(1) Includes closed contracts which have not yet settled and the current portion of open contracts.

Other assets consisted of the following (in thousands):

	December 31,	
	2023	2022
Operating lease right-of-use assets	$ 10,515	$ 10,364
Investment in White Cap, LLC	2,182	2,453
Proportional consolidation of Monza	11,694	9,321
Derivatives (1)	10,068	23,236
Other	4,464	2,175
Total other assets	$ 38,923	$ 47,549

(1) Includes open contracts.

Accrued liabilities consisted of the following (in thousands):

	December 31,	
	2023	2022
Accrued interest	$ 13,479	$ 8,967
Accrued salaries/payroll taxes/benefits	9,473	15,097
Operating lease liabilities	1,455	1,628
Derivatives (1)	6,267	46,595
Other	1,205	1,754
Total accrued liabilities	$ 31,879	$ 74,041

(1) Includes closed contracts which have not yet settled.

Other liabilities consisted of the following (in thousands):

	December 31,	
	2023	2022
Dispute related to royalty deductions	$ 5,250	$ 4,937
Derivatives	2,756	43,061
Operating lease liabilities	10,803	10,527
Other	560	609
Total other liabilities	$ 19,369	$ 59,134

Consolidated Statement of Operations Information

Under the Consolidated Appropriations Act of 2021, the Company recognized a $2.2 million and $2.1 million employee retention credit during 2023 and 2021. These amounts are included as a credit to *General and administrative expenses* in the Condensed Consolidated Statement of Operations. No such credit was received during 2022.

During 2023 and 2022, *Other expense (income), net* primarily consisted of additional expenses for net abandonment obligations pertaining to a number of legacy Gulf of Mexico properties. During 2021, *Other expense (income), net* primarily consisted of income related to the release restrictions on the Black Elk Escrow fund, partially offset by expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program, offset by contingent decommissioning obligation.

Consolidated Statement of Cash Flows Information

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

	Year Ended December 31,		
	2023	2022	2021
Cash and cash equivalents	$ 173,338	$ 461,357	$ 245,799
Restricted cash	4,417	4,417	4,417
Cash, cash equivalents and restricted cash	177,755	465,774	250,216
Supplemental cash flows information:			
Cash paid for interest	42,132	71,126	64,805
Cash paid for income taxes	2,392	8,198	152
Non-cash investing activities:			
Accruals of property and equipment	7,165	6,636	9,464
ARO - additions, dispositions and revisions, net	37,337	91,652	36,175

NOTE 17 — COMMITMENTS

Pursuant to the 2010 Purchase and Sale Agreement with Total E&P, the Company may fulfill security requirements related to ARO for certain properties through securing surety bonds, through making payments to an escrow account under a formula pursuant to the agreement, or a combination thereof, until certain prescribed thresholds are met. As of December 31, 2023, the Company had surety bonds related to the agreement totaling $103.0 million and had $0.4 million in escrow. There is no further escalation of the threshold after 2023.

Pursuant to the 2010 Purchase and Sale Agreement with Shell Offshore Inc. related to ARO for certain properties, the Company has surety bonds that are subject to re-appraisal by either party. As of December 31, 2023, neither party had requested a re-appraisal to be made. The current security requirement of $64.0 million could be increased up to $94.0 million depending on certain conditions and circumstances.

Pursuant to the 2019 Purchase and Sale Agreement with Exxon related to ARO for certain properties, the Company was required to obtain $36.3 million of surety bonds as of December 31, 2023. This amount increases on June 1 of the following years to $44.0 million - 2024; $48.3 million - 2025; $53.2 million - 2026; $58.5 million - 2027, and future increases in increments ranging $5.9 million to $10.4 million per year until the total amount reaches $114.0 million in 2034. The Company may request a redetermination with Exxon every two years by providing certain documentation as provided in the purchase agreement. The Company is required to maintain this scheduled level of bonds until the properties are fully plugged, abandoned, and restored in accordance with applicable laws and regulations.

Pursuant to the 2019 Purchase and Sale Agreement with Conoco related to ARO for certain properties, the Company was required to obtain $49.0 million of surety bonds and is required to maintain this level of bonds until the properties are fully plugged, abandoned, and restored in accordance with applicable laws and regulations.

The Company also has surety bonds primarily related to decommissioning obligations. Total expenses related to these surety bonds, inclusive of the surety bonds in connection with the agreements described above, were $7.4 million, $8.3 million and $6.0 million during 2023, 2022 and 2021, respectively. Future surety bonds costs may change due to a number of factors, including changes and interpretations of regulations by the BOEM, rates being charged in the market place 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 $1.0 million, $1.6 million and $2.1 million for the difference between the quantities shipped and the minimum obligations during 2023, 2022 and 2021, respectively.

The Company entered into a drilling contract during 2023. The contract is to begin in February 2025 and terminate in October 2025. The Company expects the total obligation under the contract to be approximately $9.9 million.

NOTE 18 — RELATED PARTIES

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

On May 15, 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 2 – Debt*). The terms of this transaction were reviewed and approved by the Audit Committee of the Company's board of directors.

The aircraft was purchased as part of a series of transactions pursuant to which the Company restructured the compensation for its Named Executive Officers. In connection with the Company's efforts to reduce overall executive compensation, including perquisite compensation the CEO was receiving for personal use of the aircraft, the Company entered into an amendment to the employment agreement with the CEO in April 2023. This amendment requires that the Company be reimbursed for personal use of the aircraft in accordance with the Company's aircraft use policy.

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, $1.7 million and $0.6 million for the each of the years ended 2023, 2022 and 2021, 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 $0.4 million, $0.2 million and $0.2 million during 2023, 2022 and 2021, 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 $16.5 million, $20.0 million and $12.0 million during 2023, 2022 and 2021, respectively. The spouse received commissions partially based on services rendered to the Company which were approximately $0.1 million in each of 2023, 2022 and 2021.

An entity controlled by the Company's CEO was a holder of the Company's 9.75% Notes in the principal amount of $8.0 million. The 9.75% Notes were redeemed in February 2023.

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 lenders.

An entity indirectly owned and controlled by the Company's CEO is the sole lender under the Credit Agreement (see *Note 2 – Debt*). In relation to the execution of amendments to the Credit Agreement, the Company paid arrangement and extension fees of approximately $1.1 million and $0.8 million in 2022 and 2021, respectively, and paid legal fees on behalf of the entity of approximately $0.1 million and $0.2 million in 2022 and 2021, respectively. No arrangements fees or legal fees were paid in 2023. In addition, during 2023, 2022 and 2021, the entity earned commitment fees of $1.5 million, $1.5 million and $1.0 million, respectively, equal to 3.0% of the unused borrowing base lending commitment.

See *Note 6 – Joint Venture Drilling Program* for information on related party transactions concerning Monza.

NOTE 19 — CONTINGENCIES

Appeal with ONRR

In 2009, the Company recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their 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. The Company disagrees with the position taken by the ONRR and filed an appeal with the ONRR. The Company was required to post a surety bond in order to appeal the Interior Board of Land Appeals decision. As of December 31, 2023, the value of the surety bond posted is $8.9 million.

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

On September 18, 2023, the Company received notification from the ONRR regarding results of an audit performed on W&T's historical refund claims taken on various properties for alleged royalties owed to the ONRR. The Company's review and the ONRR appeal process are ongoing, and the Company does not believe any accrual is necessary at this time.

Civil Penalties Assessment

In January 2021, the Company executed a Settlement Agreement with BSEE which resolved nine pending civil penalties issued by BSEE. The civil penalties pertained to INCs issued by BSEE alleging regulatory non-compliance at separate offshore locations on various dates between July 2012 and January 2018. Under the Settlement Agreement, the Company agreed to pay a total of $0.7 million in three annual installments. The final installment was paid in February 2023.

Contingent Decommissioning Obligations

The Company may be subject to retained liabilities with respect to certain divested property interests by operation of law. 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 2023, the Company incurred $8.5 million in costs related to these decommissioning obligations and recorded an additional $6.2 million of anticipated decommissioning obligations. As of December 31, 2023, the remaining loss contingency recorded related to the anticipated decommissioning obligations is $18.0 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 that the Company does incur costs associated with these properties 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 the ordinary course of its business. 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, the Company 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 20 — 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,		
	2023	2022	2021
Proved oil and natural gas properties and equipment	$ 8,919,403	$ 8,813,404	$ 8,636,408
Accumulated depreciation, depletion and amortization	(8,200,968)	(8,088,271)	(7,981,271)
Net capitalized costs related to producing activities	$ 718,435	$ 725,133	$ 655,137
Depreciation, depletion and amortization ($/Boe)	8.85	7.32	6.50

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,		
	2023	2022	2021
Acquisition of proved oil and natural gas properties (1)	$ 43,736	$ 78,565	$ 2,197
Exploration costs (2)	12,250	24,498	18,444
Development costs (3)	54,022	77,282	47,218
Total	$ 110,008	$ 180,345	$ 67,859

(1) Includes capitalized ARO of $16.4 million and $33.2 million during 2023 and 2022, respectively. There was no capitalized ARO related to acquisitions during 2021.

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

(2) Includes seismic costs of $2.8 million, $5.6 million, and $0.1 million incurred during 2023, 2022 and 2021, respectively. Includes geological and geophysical costs charged to expense of $4.8 million, $5.5 million, and $5.7 million during 2023, 2022 and 2021, respectively.

(3) Includes net additions from capitalized ARO of $21.0 million, $55.6 million, and $36.2 million during 2023, 2022 and 2021, 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 Mexico. 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.

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, 2020	32.2	17.4	569.3	144.4
Revisions of previous estimates	10.0	3.1	83.0	27.1
Purchase of minerals in place	—	—	0.1	—
Production	(5.0)	(1.4)	(44.8)	(13.9)
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)
Extensions and discoveries	—	—	—	—
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
Year-end proved developed reserves:				
2023	27.4	12.7	379.4	103.3
2022	31.1	17.6	576.0	144.8
2021	27.6	17.8	549.2	137.0
Year-end proved undeveloped reserves:				
2023	9.6	1.0	54.6	19.7
2022	9.5	1.3	58.6	20.5
2021	9.6	1.3	58.4	20.6

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.

During 2021, increases in revisions of previous estimates were primarily due to upward revisions to the Garden Banks 783 (Magnolia) field combined with increases due to SEC price revisions for all proved reserves.

The Company believes that it will be able to develop all but 3.1 MMBoe (approximately 16%) of the total 19.7 MMBoe classified as PUDs at December 31, 2023 within five years from the date such PUDs were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field (“Matterhorn”), Ship Shoal 349 and Viosca Knoll 823 (“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, Ship Shoal 349 and Virgo, will be delayed until an existing well is depleted and available to sidetrack. The Company also plans to recomplete and convert an existing producer at Matterhorn to water injection for improved recovery following depletion of existing well. Based on the latest reserve report, these PUD locations are expected to be developed in 2025 and 2035.

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,		
	2023	2022	2021
Future cash inflows	$ 4,282.3	$ 8,856.0	$ 5,178.0
Future costs:			
Production	(2,007.6)	(2,895.0)	(2,062.0)
Development and abandonment	(1,052.3)	(990.0)	(976.0)
Income taxes	(210.3)	(1,006.0)	(359.0)
Future net cash inflows	1,012.1	3,965.0	1,781.0
10% annual discount factor	(328.9)	(1,702.0)	(625.0)
Standardized measure of discounted future net cash flows	$ 683.2	$ 2,263.0	$ 1,156.0

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 oil realized price. Then, this ratio is applied to the oil price using SEC guidance. The average base commodity prices used to determine the standardized measure are as follows:

	December 31,		
	2023	2022	2021
Oil ($/Bbl)	$ 74.79	$ 91.50	$ 65.25
NGLs ($/Bbl)	24.08	41.92	26.83
Natural gas ($/Mcf)	2.74	6.85	3.68

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,		
	2023	2022	2021
Standardized measure, beginning of year	$ 2,263.0	$ 1,156.0	$ 493.7
Sales and transfers of oil, NGL and natural gas produced, net of production costs	(240.1)	(672.7)	(370.4)
Net changes in prices and production costs	(1,241.4)	1,368.6	980.9
Net change in future development costs	(22.0)	(15.2)	(24.7)
Revisions of quantity estimates	(828.8)	249.1	289.6
Acquisition of reserves in place	72.0	225.2	0.3
Accretion of discount	285.7	138.1	44.0
Net change in income taxes	443.1	(369.3)	(181.8)
Changes in timing and other	(48.3)	183.2	(75.6)
Standardized measure, end of year	$ 683.2	$ 2,263.0	$ 1,156.0

NOTE 21 — SUBSEQUENT EVENTS

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 Mexico, among other assets, for a gross purchase price of $72.0 million, subject to customary purchase price adjustments. The transaction closed on January 16, 2024 for $76.9 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. The Company is in the process of completing the preliminary purchase price allocation of the assets acquired and the liabilities assumed.

On January 26, 2024, the Company entered into a Fourteenth Amendment to the Credit Agreement to extend the maturity date of the Credit Agreement to February 29, 2024.

On February 28, 2024, the Company entered into a Fifteenth Amendment to the Credit Agreement to extend the maturity date of the Credit Agreement to March 28, 2024.

On March 5, 2024, the board of directors approved a first quarter dividend of $0.01 per share. The Company expects to pay the dividend on March 25, 2024, to stockholders of record as of the close of business on March 18, 2024.

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, 2023. 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, 2023 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, 2023, 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, 2023.

The effectiveness of our internal control over financial reporting as of December 31, 2023 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Attestation Report of the Registered Public Accounting Firm

Ernst & Young 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, 2023 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, 2023, 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	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	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)
10.31	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)
10.32	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)
10.33+	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)
10.34+	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)
10.35+	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)
10.36+	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)
10.37+	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)
10.38+	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)

10.39+	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)
10.40+	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)
10.41+	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)
10.42+	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)
21.1*	Subsidiaries of the Registrant
23.1*	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm
23.2*	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
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.

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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 6, 2024.

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 6, 2024.

/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/ DANIEL O. CONWILL IV **Daniel O. Conwill IV**	Director
/S/ B. FRANK STANLEY **B. Frank Stanley**	Director
/S/ DR. NANCY CHANG **Dr. Nancy Chang**	Director

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 23.1

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. 333-260248) of W&T Offshore, Inc.,

(2) Registration Statement (Form S-3 No. 333-214168) of W&T Offshore, Inc.,

(3) Registration Statement (Form S-8 No. 333-219747) pertaining to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, as amended, and

(4) Registration Statement (Form S-8 No. 333-272794) pertaining to the W&T Offshore, Inc. 2023 Incentive Compensation Plan

of our reports dated March 6, 2024, with respect to the consolidated financial statements of W&T Offshore, Inc. and subsidiaries, and the effectiveness of internal control over financial reporting of W&T Offshore, Inc. and subsidiaries included in this Annual Report (Form 10-K) for the year ended December 31, 2023.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 6, 2024

Exhibit 23.2

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 6, 2024, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated January 24, 2024, 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, 2023", and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2018, 2019, 2020, 2021 and 2022. We further consent to the incorporation by reference of information contained in our report dated January 24, 2024, in the Registration Statements (Form S-3 Nos. 333-260248 and 333-214168) of W&T Offshore, Inc., in the Registration Statement (Form S-8 No. 333-219747) pertaining to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan and in the Registration Statement (Form S-8 No. 333-272794) pertaining to the W&T Offshore, Inc. 2023 Incentive Compensation Plan. 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 6, 2024

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 6, 2024

/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 6, 2024

/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, 2023 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 6, 2024

/s/ Tracy W. Krohn
Tracy W. Krohn
Chairman, Chief Executive Officer, President and Director
(Principal Executive Officer)

Date: March 6, 2024

/s/ Sameer Parasnis
Sameer Parasnis
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 97.1

W&T OFFSHORE, INC.

CLAWBACK POLICY

Purpose

The Board of Directors (the "Board") of W&T Offshore, Inc. (the "Company") has adopted this policy which provides for the recoupment of certain executive compensation in the event of a required accounting restatement of the Company's financial statements due to material noncompliance with financial reporting requirements under the U.S. federal securities laws (which shall exclude any restatement caused by a change in applicable accounting rules or interpretations), or an error or mistake in the calculation of a performance metric or goal that was the basis of the payment of incentive-based compensation (as defined below) (the "Policy"). This Policy is designed to comply with Section 10D of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the rules promulgated thereunder, and the listing standards of the national securities exchange on which the Company's securities are listed.

Administration

This Policy shall be administered by the Compensation Committee of the Board (the "Committee"). Any determinations made by the Committee shall be final and binding on all affected individuals. The Committee is authorized to interpret and construe this Policy. It is intended that this Policy be interpreted in a manner that is consistent with the requirements of Section 10D of the Exchange Act and the applicable rules or standards adopted by the Securities and Exchange Commission or any national securities exchange on which the Company's securities are listed. The Committee may require that any employment or service agreement, equity award agreement, or similar agreement or arrangement entered into on or after the Effective Date (as defined below) shall, as a condition to the grant of any benefit thereunder, require a Subject Executive (as defined below) to agree to the terms of this Policy.

Subject Executives; Recoupment; Accounting Restatement

The Committee shall, as to (i) any current or former executive officer (as determined by the Committee in accordance with Section 10D of the Exchange Act, the rules promulgated thereunder, and the listing standards of the national securities exchange on which the Company's securities are listed) and (ii) such other senior executives/employees who may from time to time be deemed subject to this Policy by the Committee (all individuals identified in clause (i) or (ii) a "Subject Executive"), cause the Company to require the reimbursement by the Subject Executive of all or a portion of any incentive-based compensation paid or awarded to the Subject Executive up to the amounts specified below where: (a) the Company is required to prepare an accounting restatement of its financial statements due to the Company's material noncompliance with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (each an "Accounting Restatement"), (b) the payment to the Subject Executive was predicated upon the achievement of certain financial results that were subsequently the subject of the Accounting Restatement or the miscalculation and (c) the amount received by the Subject Executive exceeded the amount that otherwise would have been received had it been determined based on the Accounting Restatement (the “Overpayment”).

For incentive-based compensation based on stock price or total shareholder return, where the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in the Accounting Restatement, the amount must be based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the incentive-based compensation was received; and the Company must maintain documentation of the determination of that reasonable estimate and provide such documentation to the exchange on which the Company’s securities are listed.

The Committee will require reimbursement or forfeiture of the Overpayment received by any Subject Executive during the three (3) completed fiscal years immediately preceding the date on which the Company is required to prepare an Accounting Restatement and any transition period (that results from a change in the Company’s fiscal year) within or immediately following those three (3) completed fiscal years.

In no event shall the Company be required to award Subject Executives an additional payment if the restated or accurate financial results would have resulted in a higher incentive-based compensation payment.

Incentive-Based Compensation

“Incentive-based compensation” covered by this Policy and the related amount that is subject to being clawed back by the Company means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of financial reporting measures. The incentive-based compensation covered by this Policy and the related amount that will be subject to being clawed back by the Company includes, but is not limited to:

- *Bonus*. This Policy applies to an annual bonus (including any cash-settled or equity settled annual incentive award, the settlement of which is or was contingent solely or in part upon achievement of one or more performance objectives as contemplated by W&T Offshore, Inc’s incentive compensation plan, as amended or restated from time to time, or any similar plan (the “Plan”)), paid with respect to a year to which the Accounting Restatement or miscalculation applies, except that this Policy is not applicable to any annual bonus paid solely based on satisfaction of subjective standards, such as demonstrating leadership, and/or completion of a specified employment period or paid with respect to performance for a fiscal year preceding the three (3) completed fiscal years immediately prior to the fiscal year in which the Committee determines that an Accounting Restatement or new calculation is required. The amount subject to being clawed back will be the incremental amount, without regard to any taxes paid, that the Board determines was paid in excess of the amount that would have been paid had the financial statements been in material compliance with the financial reporting requirements under U.S. federal securities laws or all calculations had been correct.

- *Restricted Stock Units and other Equity Awards*. This Policy applies to the number of shares of Company common stock issued in settlement of Restricted Stock Unit ("RSU") awards and other share-settled Awards (as defined in the Plan) granted pursuant to the Plan, the settlement of which is or was contingent in whole or in part upon achievement of one or more performance objectives as contemplated by the Plan and whose final day of the applicable performance period occurs in a year to which the Accounting Restatement or miscalculation applies, except that this Policy is not applicable to any RSU awards or other Plan awards whose final day of the applicable performance period occurs in a fiscal year preceding the three (3) completed fiscal years immediately prior to the fiscal year in which the Committee determines that an Accounting Restatement or new calculation is required. The number of shares subject to being clawed back will be the total shares without regard to any taxes paid that the Board determines were issued in excess of the number of shares that would have been issued had the financial statements been in material compliance with the financial reporting requirements under U.S. federal securities laws or all calculations had been correct. If any shares to be clawed back have been sold, then the proceeds of such sale, net of brokers' commissions, may be clawed back.

- *Sale Proceeds.* This Policy applies to proceeds from the sale of shares acquired through the Plan that were granted or vested solely or in part on satisfying one or more financial reporting measure performance objectives as contemplated by the Plan. Compensation that would not be considered incentive-based compensation includes, but is not limited to: (i) salaries; (ii) bonuses paid solely on satisfying subjective standards, such as demonstrating leadership, and/or completion of a specified employment period; (iii) non-equity incentive plan awards earned solely on satisfying strategic or operational measures; (iv) wholly time-based equity awards; and (v) discretionary bonuses or other compensation that is not paid from a bonus pool that is determined by satisfying one or more financial reporting measures as contemplated by the Plan.

Incentive-based compensation is deemed received in the Company's fiscal period during which the financial reporting measure specified in the incentive-based compensation award is attained, even if the payment or grant of the incentive-based compensation occurs after the end of that period.

<u>Method of Recoupment</u>

The Committee shall have sole discretion in determining the form, amount and timing of the recoupment of any Overpayment, subject to applicable stock exchange rules and law. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company pursuant to the terms of any similar policy in any employment agreement, equity award agreement, or similar agreement and any other legal remedies available to the Company, including:

- requiring reimbursement of cash incentive-based compensation previously paid;

- seeking recovery of any gain realized on the vesting, exercise, settlement, sale, transfer, or other disposition of any equity-based awards granted as incentive based compensation;

- offsetting the recouped amount from any compensation otherwise owed by the Company to the Subject Executive;
- cancelling outstanding vested or unvested equity awards; and/or
- taking any other remedial and recovery action permitted by law, as determined by the Committee.

In lieu of requiring a claw back of amounts in accordance with the above bullet points, the Committee may claw back unvested equity awards, as determined by the Committee.

Impracticability

The Committee shall recover any Overpayment in accordance with this Policy except to the extent that the Committee determines such recovery would be impracticable because:

- direct expenses paid to a third party to assist in enforcing the policy would exceed the amount to be recovered;
- recovery would violate home country law where that law was adopted prior to November 28, 2022; or
- recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

No Indemnification

The Company shall not indemnify any Subject Executive against the loss of any incorrectly awarded incentive-based compensation.

Each Subject Executive's acceptance of incentive-based compensation shall constitute his or her agreement (i) to be bound by this Policy and (ii) to not seek indemnification or contribution from the Company for any amounts clawed back.

Before the Committee determines to seek recovery pursuant to this Policy, it shall provide to the Subject Executive written notice and the opportunity to be heard at a meeting of the Board of Directors of the Company.

Effective Date

This Policy shall be effective as of December 1, 2023 (the "Effective Date") and shall apply to Incentive-based compensation (including Incentive-based compensation granted pursuant to arrangements existing prior to the Effective Date). Notwithstanding the foregoing, this Policy shall only apply to Incentive-based compensation received (as determined pursuant to this Policy) on or after October 2, 2023.

Amendment or Termination

The Board may amend this Policy from time to time in its discretion. The Board may terminate this Policy at any time.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 24, 2024

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, 2023, 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'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, 2023, to be:

	Net Reserves			Future Net Revenue(1) (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	22,202.4	10,051.9	299,361.8	1,026,883.0	750,118.1
Proved Developed Non-Producing	5,167.7	2,664.1	80,058.5	388,956.5	204,058.5
Proved Undeveloped	9,575.5	1,008.7	54,566.9	305,403.2	126,719.7
Total Proved	36,945.7	13,724.7	433,987.1	1,721,242.7	1,080,896.3

Totals may not add because of rounding.

(1) Future net revenue does not include estimated abandonment costs.

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 three 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. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is 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 through December 2023. For oil and NGL volumes, the average West Texas Intermediate spot price of $78.21 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.637 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 $74.79 per barrel of oil, $24.08 per barrel of NGL, and $2.739 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; the minimum transportation obligation extends beyond the economic life of the 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 (AFEs) prepared for internal approval and, if applicable, external interest owner approval. If an AFE was not available, W&T provided cost estimates based on recent activity similar in scope to the proposed project. 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. 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. Gregory S. Cohen, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2013 and has over 14 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, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

By: /s/ Gregory S. Cohen
Gregory S. Cohen, P.E. 117412
Vice President

Date Signed: January 24, 2024

By: /s/ Ruurdjan (Rudi) de Zoeten
Ruurdjan (Rudi) de Zoeten, P.G. 3179
Vice President

Date Signed: January 24, 2024

GSC:ARS

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

(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.

(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

(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.*

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> *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):*
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> *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.*
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> *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:*
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> - *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.