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, 2022

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 $407,404,050 based on the closing sale price of $4.32 per share as reported by the New York Stock Exchange on June 30, 2022.

The number of shares of the registrant's common stock outstanding on February 28, 2023 was 146,460,902.

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, particularly the recent rise to historically high levels;
- the length, scope and severity of the COVID-19 pandemic or the emergence of a new pandemic, including the effects of related public health concerns and the impact of actions taken by governmental authorities and other third parties in response to the pandemic and its impact on commodity prices, supply and demand considerations, global supply chain disruptions and labor constraints;
- global economic trends, geopolitical risks and general economic and industry conditions, such as the economic impact from the COVID-19 pandemic, including the global supply chain disruptions and the government interventions into the financial markets and economy, among other factors;

- volatility of oil, natural gas and NGL 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, natural gas and NGLs, including due to the actions of foreign producers, importantly including OPEC and other major oil producing companies ("OPEC Plus") and change in OPEC Plus'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 and pandemics;
- 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 natural gas, oil and NGLs 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

- Depressed oil, natural gas or NGL prices adversely affects 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.
- Commodity derivative positions may limit our potential gains.
- 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

- 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.
- Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and 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.
- 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.
- 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.
- Insurance for well control and hurricane damage may become significantly more expensive for less coverage and some losses currently covered by insurance may not be covered in the future.
- 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.
- A pandemic, such as the COVID-19 pandemic, may have an adverse effect on our business, liquidity, results of operations and financial condition.
- 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.

- Many laws and regulations regarding data privacy and security to which we 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 have historically outsourced substantially all of our information technology infrastructure and the management and servicing of such infrastructure, which makes us more dependent upon third parties and exposed to related risks. We are in the process of transitioning substantially all of such infrastructure, 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

- 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.
- 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.
- 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 and Regulatory Risks

- Environmental regulations and liabilities, including those related to climate change, additional deepwater drilling laws, regulations and other restrictions, delays and other offshore-related developments in the Gulf of Mexico may increase our costs and adversely affect our business.
- 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.
- Our estimates of future ARO may vary significantly from period to period and are especially significant because our operations are concentrated in the Gulf of Mexico.
- Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to MPAs and endangered and threatened species.
- 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 a gas.

Boe. Barrel of oil equivalent determined using the ratio of six Mcf of Natural Gas to one barrel of crude 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.

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.

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 MMS Minerals Revenue Management Program.

OPEC. Organization of Petroleum Exporting Countries.

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. 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 (“API”) 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, 2022 we held working interests in 47 offshore producing fields in federal and state waters. Our acreage, well, production and reserves information is 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. At W&T Offshore, 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 particularly as we focus on optimizing costs.

- *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.* At W&T, we grow in opportunistic ways as we manage our balance sheet prudently and reinvest free cash flow. Our existing portfolio of 154 structures (116 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 reduce debt, thus optimizing the balance sheet and maintaining financial flexibility. We also intend to use a portion of the free cash flow we generate to reduce our outstanding debt to maintain flexibility for future opportunities.

- *Management of 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, HSE&R, Legal, Human Resources, Investor Relations, 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 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 2022, we published our second annual ESG report highlighting our performance and initiatives across ESG categories for the period of 2019 to 2021, 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

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

We continually monitor current and forecasted commodity prices to assess if changes are needed to our plans. 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 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

We sell our crude oil, NGLs and natural gas to third-party customers. We are not dependent upon, or contractually limited to, any one customer or small group of customers. In 2022, approximately 31% 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 2022 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, provided that replacement customers could be obtained in a relatively short period of time on terms, conditions, and pricing substantially similar to those currently existing. We do not have any agreements which obligate us to deliver a fixed volume of physical products to customers.

Compliance with Government Regulations

Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulations as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. BOEM and BSEE, both agencies under the U.S. Department of the Interior (“DOI”), have adopted regulations pursuant to the Outer Continental Shelf Lands Act (“OCSLA”) that apply to our operations on federal leases in the Gulf of Mexico.

The Federal Energy Regulatory Commission (“FERC”) regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. Sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at uncontrolled market prices. The FERC also regulates rates and service conditions for the interstate transportation of liquids, including crude oil, condensate and NGLs, under various statutes.

The Federal Trade Commission (“FTC”), the FERC and the Commodity Futures Trading Commission (“CFTC”) hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. We are required to observe the market related regulations enforced by these agencies with regard to our physical sales of crude oil or other energy commodities, and any related hedging activities that we undertake. Any violation of the FTC, FERC, and CFTC prohibitions on market manipulation can result in substantial civil penalties amounting to almost $1.5 million per violation per day.

These departments and agencies have substantial enforcement authority and the ability to grant and suspend operations, and to levy substantial penalties for non-compliance. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

Federal leases. Most of our offshore operations are conducted on federal oil and natural gas leases in the OCS waters of the Gulf of Mexico. The DOI has delegated its authority to issue federal leases granted under the OCSLA to the BOEM, which has adopted and implemented regulations relating to the issuance and operation of oil and natural gas leases on the OCS. These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms. These leases require compliance with the BOEM, the BSEE, and other government agency regulations and orders that are subject to interpretation and change. The BSEE also regulates the plugging and abandonment of wells located on the OCS and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines on the OCS (collectively, these activities are referred to as "decommissioning"), while the BOEM governs financial assurance requirements associated with those decommissioning obligations.

President Biden has made tackling climate change, including the restriction or elimination of future greenhouse gas ("GHGs") emissions, a priority in his administration. The Biden Administration has already adopted several executive orders and is expected to pursue additional orders and pursue legislation, regulations or other regulatory initiatives in support of this regulatory agenda. Notably, President Biden issued an executive order in January 2021 suspending new leasing activities for oil and gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and gas permitting and leasing practices. The suspension of these federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district court in June 2021, effectively halting implementation of the leasing suspension. Subsequent federal litigation, however has impeded the most recent federal oil and gas lease sale (Lease Sale 257) in the Gulf of Mexico requiring the DOI to conduct a new environmental analysis that takes into consideration such climate effects before holding another sale. In August 2022, the Fifth Circuit vacated the injunction blocking the leasing moratorium, allowing the Biden Administration to continue implementing the pause. However, in compliance with the Inflation Reduction Act of 2022, the BOEM reinstated Lease Sale 257 in September 2022. The BOEM has continued to plan for upcoming offshore lease sales as required by the OCSLA. In July 2022, the BOEM published the 2023-2028 National Outer Continental Shelf Drilling and Leasing Proposed Program, which contemplates eleven future lease sales. In November 2021, the DOI released its report on federal oil and gas leasing and permitting practices. The report includes recommendations in respect to offshore sector, including adjusting royalty rates to ensure that the full value of the tracts being leased are captured, strengthening financial assurance coverage amounts that are required by operators, establishing a "fitness to operate" criteria that companies would need to meet in respect of safety, environmental and financial responsibilities in order to operate on the OCS. Several of the report recommendations require action by the Congress and cannot be implemented unilaterally by the Biden Administration; however, in April 2022, the DOI published sale notices for June 2022 onshore lease sales that incorporated certain recommendations in the DOI's report, including significantly reduced acreage of land available for leasing on public lands and an increased royalty rate of 18.75%, up from the current rates of 12.50% to 16.67%. We continue to conduct our operations on our existing leases in the OCS; however, uncertainty on future Biden Administration actions with regard to offshore oil and gas activities on the OCS together with the issuance of any future executive orders or adoption and implementation of laws, rules or initiatives that further restrict, delay or result in cancellation of existing oil and gas activities on the OCS could have a material adverse effect on our business and operations.

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 on the OCS. In 2016, the BOEM under the Obama Administration issued Notice to Lessees and Operators 2016-N01 (the "2016 NTL") to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, rights of way ("ROWs") and rights of use and easement ("RUEs"). The 2016 NTL was not fully implemented as the BOEM under the Trump Administration rescinded the 2016 NTL in 2020. In October 2020, BOEM published jointly with BSEE a proposed rule that sought to clarify and provide greater transparency to decommissioning and related financial assurance requirements imposed on record title owners and operating rights owners of interests in federal OCS leases and RUE and ROW grant holders conducting operations on the federal OCS. A final rule was expected by December 2022 but has not yet been published. In August 2021, the BOEM announced expanded requirements for supplemental financial assurance for properties with property owners who are not deemed to be financially strong by the BOEM. In addition to sole liability properties where the owner is not financially strong, the BOEM will require supplemental financial assurance for certain high-risk, non-sole liability properties.

Consistent with the November 2021 DOI leasing report recommendations and in response to President Biden's January 2021 executive order, the Biden Administration could pursue more stringent decommissioning and financial assurance requirements that could increase our operating costs. According to the federal government's Fall 2022 Unified Regulatory Agenda, the BOEM and the BSEE are expected to finalize the policies and procedures concerning compliance with OCS oil and gas decommissioning obligations originally proposed under the Trump Administration. In addition, BOEM is expected to propose a new rule in respect of financial assurance requirements to ensure compliance with OCS obligations. The BOEM has the authority to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

Reporting of decommissioning expenditures. Under applicable BSEE regulations, lessees operating on the OCS and conducting decommissioning activities are required to submit summaries of actual expenditures for decommissioning of subject wells, platforms, and other facilities. The BSEE has reported that it uses this summary information to better estimate future decommissioning liabilities. See *Risk Factors* under Part I, Item 1A, *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 and *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K for more discussion 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 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 FERC ratemaking authority, and 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 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 on 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 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 crude 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 crude oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for crude oil, condensate, NGLs and other products are regulated by the FERC. In general, interstate crude 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 crude 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 crude oil, condensate or NGL pipelines will affect us in a way that materially differs from the way they affect other crude oil, condensate and NGL producers or marketers.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits, bonds and pollution liability insurance for the drilling of wells, regulating the location of wells, the method of drilling, casing, operating, plugging and abandoning wells, and governing the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation of oil and gas resources, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing of such wells.

Tropical storms, hurricanes and other weather events in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past tropical storms and hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. Damage can occur both above the water line and to subsea infrastructure. The BOEM and the BSEE continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEM and the BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures.

Compliance with Environmental Regulations

General. We are subject to complex and stringent federal, state and local environmental laws. These laws, 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. 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. Certain environmental laws, such as the federal Oil Pollution Act of 1990, as amended (“OPA”) impose strict joint and several liability for environmental contamination, such as may arise in the event of an accidental spill on the OCS, rendering a person liable for environmental damage and cleanup costs without regard to negligence or fault on the part of such person. The regulatory burden on the oil and gas industry increases our cost of doing business and consequently affects our profitability. The cost of remediation, reclamation and decommissioning, including abandonment of wells, platforms and other facilities in the Gulf of Mexico is significant. These costs are considered a normal, recurring cost of our on-going operations. Our competitors are subject to the same laws and regulations.

Hazardous Substances and Wastes. The federal Comprehensive Environmental Response, Compensation, and Liability Act, as amended, (“CERCLA”) imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons are subject to strict joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies.

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (“RCRA”), regulates the generation, transportation, storage, treatment and disposal of non-hazardous and hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and certain other wastes associated with the exploration, development or production of oil and natural gas from regulation as “hazardous waste”, and the disposal of such oil and natural gas exploration, development and production wastes is regulated under less onerous non-hazardous waste requirements, usually under state law.

Standards have been developed under RCRA and/or state laws for worker protection from exposure to Naturally Occurring Radioactive Materials (“NORM”), treatment, storage, and disposal of NORM and NORM waste, and management of NORM-contaminated piping valves, containers and tanks. Historically, we have not incurred any material expenditures in connection with our compliance with the existing RCRA and applicable state laws related to NORM waste.

Air Emissions and Climate Change. Air emissions from our operations are subject to the federal Clean Air Act, as amended (“CAA”), and comparable state and local requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For example, in 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard (“NAAQS”) for ground level ozone from 75 to 70 parts per billion. Since that time, the EPA issued area designations with respect to ground-level ozone and, in December 2020, published notice of a final action to retain the 2015 ozone NAAQS without revision on a going-forward basis. However, the EPA is currently re-writing a draft policy assessment that is a key component of the agency’s reconsideration of the 2015 NAAQS for ozone, raising the possibility that the EPA may tighten the standards in the future. The EPA is expected to issue a proposed rule in April 2023 and a final rule by the end of 2023.

The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States and in foreign countries. As a result, numerous proposals have been made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHG as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG 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. Furthermore, many state and local leaders have intensified or stated their intent to intensify efforts to support international climate commitments and treaties. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, such legislation has periodically been introduced in the U.S. Congress and may be proposed or adopted in the future. Further, the EPA has adopted regulations under the existing CAA that, among other things, impose preconstruction and operating permit requirements on certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources, and implement New Source Performance Standards directing the reduction of methane emissions from certain new, modified or reconstructed facilities in the oil and natural gas sector. In November 2021, the EPA issued a proposed rule intended to reduce methane emissions from new and existing crude oil and natural gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters". According to the Fall 2022 Unified Regulatory Agenda, the EPA is expected to issue a final rule by August 2023. Additionally, in August 2022, President Biden signed into law the Inflation Reduction Act of 2022, which, among other things, includes a methane emissions reduction program. 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.

Additionally, on March 21, 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, information about the registrant's governance of climate-related risks and relevant risk management processes; climate-related risks that are reasonably likely to have a material impact on the registrant's business, results of operations, or financial condition and their actual and likely climate-related impacts on the registrant's business strategy, model, and outlook; climate-related targets, goals and transition plan (if any); certain climate-related financial statement metrics in a note to their audited financial statements; Scope 1 and Scope 2 GHG emissions; and Scope 3 GHG emissions and intensity, if material, or if the registrant has set a GHG emissions reduction target, goal or plan that includes Scope 3 GHG emissions. 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.

At the international level, there exists 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, known as Nationally Determined Contributions, every five years after 2020 to reduce domestic GHG emissions. Although the United States withdrew from the Paris Agreement, President Biden recommitted the United States to the Paris Agreement in April 2021. Pursuant to its obligations as a signatory to the Paris Agreement in November 2020, the United States has set a target to reduce its GHG emissions by 50-52% by the year 2030 as compared with 2005 levels and has agreed to provide periodic updates on its progress. Additionally, at the 26th Conference of the Parties ("COP26") in November 2021, the United States and European Union jointly announced the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. COP26 concluded with the finalization of 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 27th Conference of the Parties ("COP27"), President Biden announced the EPA's proposed standards to reduce methane emissions from existing oil and gas sources, and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time.

The OCSLA authorized 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 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 agency also reviews BOEM-mandated monitoring and reporting of air emission sources for compliance with approved plan emission limits. BSEE may initiate 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 ("INC") or recommending further enforcement action against potential violators.

Water Discharges. The primary federal law for oil spill liability is the OPA which amends and augments oil spill provisions of the federal Water Pollution Control Act (the "Clean Water Act"). OPA imposes certain duties and liabilities on "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters, including the OCS or adjoining shorelines. A "responsible party" includes the owner or operator of an onshore facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns strict, joint and several liability, without regard to fault, to each responsible party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to oil and natural resource related damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. In January 2018, the BOEM raised OPA's damages liability cap to approximately $137.7 million; however, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party failed to report a spill or cooperate fully in the cleanup. OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill, and to prepare and submit for approval oil spill response plans. These oil spill response plans must detail the action to be taken in the event of a spill; identify contracted spill response equipment, materials, and trained personnel; and identify the time necessary to deploy these resources in the event of a spill. In addition, OPA currently requires a minimum financial responsibility demonstration of between $35.0 million and $150.0 million for companies operating on the OCS. We are currently required to demonstrate, on an annual basis, that we have ready access to $35.0 million that can be used to respond to an oil spill from our facilities on the OCS.

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the monitoring and discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The EPA has also adopted regulations requiring certain onshore oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. The treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from our onshore gas processing plant have compliance costs. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of significant quantities of oil. Our Board of Directors reviews our Clean Water Act compliance metrics on a quarterly basis.

Marine Protected Areas and Endangered and Threatened Species. Executive Order 13158, issued in May 2000, directs federal agencies to safeguard existing Marine Protected Areas (“MPAs”) in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. In addition, Federal Lease Stipulations include regulations regarding the taking of protected marine species (such as sea turtles, marine mammals, Gulf sturgeon and other listed marine species).

Certain flora and fauna that have been officially classified as “threatened” or “endangered” are protected by the federal Endangered Species Act, as amended (“ESA”) and the Marine Mammal Protection Act, as amended (“MMPA”). These laws prohibit any activities that could “take” a protected plant or animal or reduce or degrade its habitat area. The U.S. Fish and Wildlife Service (“USFWS”) under former President Trump issued a final rule in January 2021, which clarified that criminal liability under the Migratory Bird Treaty Act (“MBTA”) would apply only to actions “directed at” migratory birds, its nests, or its eggs; however, in October 2021, the USFWS under the Biden Administration revoked the Trump Administration’s rule on incidental take and published an advanced notice of proposed rulemaking to codify a general prohibition on incidental take while establishing a process to regulate or permit exceptions to such a prohibition. The final rule became effective in December 2021. Additionally, in June and July 2022, the USFWS and the National Marine Fisheries Service (“NMFS”) rescinded the Trump Administration’s definition of “habitat” for the purpose of critical habitat designation and the rule setting forth procedures for USFWS critical habitat designations. The USFWS and NMFS may make determinations on the listing of species as threatened or endangered under the ESA or MMPA and litigation with respect to the listing or non-listing of certain species may result in more fulsome protections for non-protected or lesser-protected species. We conduct operations on leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA or MMPA may exist.

Other federal statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Emergency Planning and Community Right-to-Know Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Magnuson-Stevens Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and related implementing regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness, wetlands or other protected areas. Operations in such protected areas may require certain mitigation measures to avoid harm to protected species, and such laws and regulations may impose additional costs on our operations.

The leases and permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. Moreover, applicable leasing and permitting programs may be subject to legislative, regulatory or executive actions to delay or suspend the issuance of leases and permits. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

Insurance Coverage

Our oil and natural gas operations are subject to risks incident to the operation of oil and gas wells, including, but not limited to, uncontrolled flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution or other risks, any of which could result in substantial losses to us. In addition, our oil and natural gas properties are located in the Gulf of Mexico, which makes us more vulnerable to tropical storms and hurricanes. These hazards can cause 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. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flow. Although we obtain insurance against some of these risks, 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 have insurance policies to cover some of our risk of loss associated with our operations, and we maintain the amount of insurance we believe is prudent. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost). Our general and excess liability policies, among others, are effective for one year beginning May 1, 2022 and 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. With respect to the Oil Spill Financial Responsibility requirement under the OPA of 1990, we are required to evidence $35.0 million of financial responsibility to the BSEE and we have insurance coverage of such amount. We currently carry multiple layers of insurance coverage in our Energy Package (defined as certain insurance policies relating to our oil and gas properties which include named windstorm coverage) covering our operating activities, with higher limits of coverage for higher valued properties and wells. The Energy Package is effective for one year beginning June 1, 2022 and 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 a retention of $17.5 million on the conventional shelf properties and $12.5 million on the deepwater properties. The operational and named windstorm coverages are effective for one year beginning June 1, 2022. Coverage for pollution causing a negative environmental impact is provided under the well control and other sections within the policy. We do not carry business interruption insurance.

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. The United States has experienced a rise in inflation since October 2021. The annual rate of inflation in the United States was measured at 6.5% in December 2022 by the Consumer Price Index. This is down from the June 2022 peak of 9.1% and represents the smallest twelve-month increase since the period ending October 2021. While currently on the decline, the annual inflation rate remains at its highest level since the early 1980s. For 2022, our realized prices for crude oil increased 41.9%, NGLs increased 19.8% and natural gas increased 86.3% from 2021. 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 to the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise.

We are experiencing some inflationary pressure for certain costs, including employees and vendors, although such cost increases did not materially impact our 2022 financial condition or results of operations, and we currently do not expect them to materially impact our 2023 financial results or operations. However, to the extent elevated inflation remains, we may experience further cost increases for our operations, including natural gas purchases and oilfield services and equipment as increasing oil, natural gas and NGL prices increase drilling activity in our areas of operations, as well as increased labor costs. An increase in oil, natural gas and NGL prices may cause the costs of materials and services to rise. We cannot predict any future trends in the rate of inflation and a significant increase in inflation, to the extent we are unable to recover higher costs through higher commodity prices and revenues, would negatively impact our business, financial condition and results of operation.

Human Capital Resources

At W&T Offshore, people are our most valuable asset. 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.

As of December 31, 2022, we had 365 employees and employed an additional 302 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.

Health and Safety. Our highest priorities are the safety of all personnel and protection of the environment. To drive a culture of personnel safety in our operations, we operate under a comprehensive Safety and Environmental Management System (“SEMS”). Our 2022 total recordable incident rate for employees was 0.54, which is far below the industry average for the Gulf of Mexico from 2021 of 9.9. 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 Health, Safety, Environmental and Regulatory (“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.

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 mirrors 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, 2022:

Category	Female	Male
Exec/Sr. Manager	22 %	78 %
Mid-Level Manager	23 %	77 %
Professionals	42 %	58 %
All Other	10 %	90 %

US Ethnicity	Exec/ Sr. Manager	Mid-Level Manager	Professionals	All Other
Asian	22 %	6 %	16 %	<1 %
Black/African American	22 %	4 %	18 %	6 %
Hispanic/Latino	11 %	8 %	7 %	6 %
Two or more races	—	2 %	—	<1 %
White	44 %	81 %	58 %	87 %
American Indian/Alaskan Native	—	—	2 %	<1 %

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, 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

Crude oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond our control. Depressed oil, natural gas or NGL prices adversely affects 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 crude 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 crude oil, NGLs and natural gas;
- events that impact global market demand (e.g. the reduced demand experienced during the COVID-19 pandemic);
- the actions of OPEC Plus;
- the price and quantity of imports of foreign crude 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 crude 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 GHG;
- 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 crude oil, NGLs 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 crude 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 crude oil, NGLs and natural gas pricing. While we have not recorded an impairment of our oil and gas properties during the year-ended December 31, 2022, 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 10 – 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 crude oil and natural gas price volatility, they may also limit future income if crude 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 crude 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, 2022, three fields, accounting for approximately 0.2 MMBoe (or 1.2%) of our 2022 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. 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 26.3% of our total proved reserves as of December 31, 2022 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.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We are and could be exposed to uninsured losses in the future. We currently carry multiple layers of insurance coverage in our Energy Package (defined as certain insurance policies relating to our oil and gas properties which include named windstorm coverage) covering our operating activities, with higher limits of coverage for higher valued properties and wells. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. Pollution and environmental risks are generally not fully insurable, as gradual seepage and pollution are not covered under our policies. Because third-party drilling contractors are used to drill our wells, we may not realize the full benefit of workmen's compensation laws in dealing with their employees.

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.

For some risks, we have not obtained insurance as we believe the cost of available insurance is excessive relative to the risks presented. We reevaluate 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 not fully insured or indemnified against losses 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 2022 financial condition or results of operations, and we currently do not expect them to materially impact our 2023 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.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

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. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. 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.

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.

Insurance for well control and hurricane damage may become significantly more expensive for less coverage and some losses currently covered by insurance may not be covered in the future.

In the past, tropical storms and hurricanes in the Gulf of Mexico have caused catastrophic losses and property damage. 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.

In the future, our insurers may not continue to offer what we view as reasonable coverage, or our costs may increase substantially as a result of increased premiums. There could be an increased risk of uninsured losses that may have been previously insured. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurance companies will not pay our claims. The occurrence of any or all of these possibilities could have a material adverse effect on our financial condition and results of operations.

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, 2022.

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 crude 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, crude 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.

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 crude 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.

A pandemic, such as the COVID-19 pandemic, may have an adverse effect on our business, liquidity, results of operations and financial condition.

The COVID-19 pandemic has resulted in periodic disruptions in demand for oil and gas commodities as various jurisdictions have attempted to implement or have implemented measures designed to contain the spread of the virus. Ongoing pandemics may have related economic repercussions that could adversely impact our business, results of operations, financial condition and cash flows. Our supply chain could be disrupted if our vendors have limited access to their facilities or labor shortages adversely affecting the price or availability of products, which could result in a loss of revenue and profitability. While demand for and prices for oil, NGLs and gas generally improved during 2022 as travel restrictions, business closures and other restrictions were lifted, an increase in infections or the onset of a new variant of the virus could again reduce demand for and prices of oil, NGLs and gas. Persistently weak or additional declines in commodity prices could adversely affect the economics of our existing operations and planned future operations. If our customers also face liquidity challenges, we could experience delays or defaults in customer payments, and we may incur increased exposure to credit risk and bad debts. Further, workforce availability may be impaired due to exposure to the pandemic, reluctance to comply with governmental, legal or contractual mandates, or other restrictions, which may adversely impact our employees' wellness and employee retention, productivity and culture, which could negatively affect our costs and profitability or negatively impact our ability to operate at full capacity and reduce our revenue.

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 recent 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 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 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.

We have historically outsourced substantially all of our information technology infrastructure and the management and servicing of such infrastructure, which makes us more dependent upon third parties and exposed to related risks. We are in the process of transitioning substantially all of such infrastructure, 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 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, AAIT, of its intention to cease providing services to us, we began the transition of information technology services and infrastructure to inside the Company or to other providers. In addition, we filed an action seeking a temporary restraining order, temporary injunction, and permanent injunction seeking, among other things, to restrain AAIT from ceasing to provide services to us until the transition process was complete. On September 16, 2022, we and AAIT mutually agreed to the terms of an agreed order issued by the court providing for a temporary injunction for a period of a minimum of 60 days from the date of the order and up to a maximum of 120 days at our option, during which AAIT would continue to provide information technology services to us and assist with the transition process.

We have moved and are continuing to move certain services within the Company and are transitioning 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 owns a significant portion of our common stock. Circumstances may arise in which he may have an interest in pursuing or preventing acquisitions, divestitures, hostile takeovers or other transactions, or conflicts of interest could arise in the future regarding, among other things, decisions related to our financing, capital expenditures and business plans, or the pursuit of certain business opportunities, including the payment of dividends or the issuance of additional equity or debt, that, in his judgment, could enhance his investment in us or in another company in which he invests. Such circumstances or conflicts might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common stock because investors may perceive disadvantages in owning shares in companies with significant stockholder concentrations.

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, 2022, we had 9.75% Senior Second Lien Notes due 2023 (the "9.75% Senior Second Lien Notes") and a term loan of certain of our subsidiaries that is non-recourse to the Company (the "Term Loan"). We have no borrowings outstanding on our revolving credit facility under our Credit Agreement, which lending commitment and final maturity is set to expire on January 3, 2024. On February 8, 2023, we redeemed all of the outstanding $552.5 million 9.75% Senior Second Lien Notes using cash on hand and the net proceeds from the offering of the $275.0 million 11.75% Senior Second Lien Notes, which notes mature on February 1, 2026 (the "11.75% Senior Second Lien Notes").

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 asset retirement obligations ("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 lenders' review of crude oil, NGLs and natural gas prices, our proved reserves and other criteria. Lower crude 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).

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% Senior Second Lien 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.

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% Senior Second Lien Notes are secured by various liens on our oil, natural gas and NGL properties, excluding our Mobile Bay assets. Our 11.75% Senior Second Lien Notes are secured by a second priority lien on substantially all of such properties. The oil and 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% Senior Second Lien Notes. In addition, we have certain rights to issue or incur additional or new secured debt, that could be secured by additional liens on the collateral and 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% Senior Second Lien 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% Senior Second Lien Notes upon a change of control.

If we experience certain kinds of changes of control, we must give holders of the 11.75% Senior Second Lien 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 the Calculus Lending facility or other agreements we may enter into in the future may prevent us from applying funds to repurchase the 11.75% Senior Second Lien 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 Calculus Lending facility 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 and Regulatory Risks

The Biden Administration may pursue significant regulatory and political actions that could adversely affect our results of operations, and our ability to implement our business strategy.

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. 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 and the Biden Administration may continue pursuing actions that delay or refuse approval of new leases for hydrocarbon exploration and development on federal lands and waters or delay or fail to grant approvals required for development of existing leases on such lands and waters. See Part I, Item 1, *Business – Compliance with Governmental Regulations* for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry pursued under the Biden Administration. To the extent that our operations in federal waters are restricted, delayed for varying lengths of time or cancelled, such developments could have a material adverse effect on our results of operations, our ability to replace reserves and the ability to implement our business strategy.

Environmental regulations and liabilities, including those related to climate change, may increase our costs and adversely affect our business.

Our operations are subject to U.S. federal, state and local and foreign environmental laws and regulations governing the protection of the environment and health and safety that impose limitations on the discharge of pollutants into the environment and establish standards for the treatment, storage, recycling and disposal of toxic and hazardous wastes. The nature of our business requires that we use, store and dispose of materials that are subject to environmental regulation. 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 at the time or in accordance with industry standards. Additionally, 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.

In certain instances, citizen groups also have the ability to bring legal proceedings against us regarding our compliance with certain environmental laws, or to challenge our ability to receive permits that we need to operate.

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. In addition, in September 2021, President Biden publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030. Since its formal launch at the United Nations Climate Change Conference (COP26), over 150 countries have joined the pledge. COP26 concluded with the finalization of 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 27th conference of parties, President Biden announced the Environmental Protection Agency's ("EPA") proposed standards to reduce methane emissions from existing oil and gas sources, and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Additionally, in August 2022, President Biden signed into law the Inflation Reduction Act of 2022 (the "IRA"). Among other things, the IRA includes a methane emissions reduction program. Additionally, while the pause on new oil and natural gas leases on public lands and offshore waters has been lifted subject to certain limitations, the impacts of these and other future orders or legislation or regulation remain unclear at this time and could have an impact on our customers, and in turn have negative effect on our business, financial conditions, results of operations, and cash flows.

Further, on March 21, 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, information about the registrant's governance of climate-related risks and relevant risk management processes; climate-related risks that are reasonably likely to have a material impact on the registrant's business, results of operations, or financial condition and their actual and likely climate-related impacts on the registrant's business strategy, model, and outlook; climate-related targets, goals and transition plan (if any); certain climate-related financial statement metrics in a note to their audited financial statements; Scope 1 and Scope 2 GHG emissions; and Scope 3 GHG emissions and intensity, if material, or if the registrant has set a GHG emissions reduction target, goal or plan that includes Scope 3 GHG emissions. 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.

Additional changes in environmental laws, regulations, guidelines or enforcement interpretations, including relating to the emission of carbon dioxide and other greenhouse gases or climate change-related concerns, 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 costs of compliance and doing business for our customers and thereby decrease the demand for our services. Because our business depends on the level of activity in the offshore oil and gas industry, existing or future laws, regulations, guidelines, enforcement interpretations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business and ability to execute our business strategy, including if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and gas or limit drilling opportunities.

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. If in the future the BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.

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 on the OCS. As of December 31, 2022, we are in compliance with our financial assurance obligations to the BOEM and have no outstanding BOEM orders, requests or financial assurance obligations. BOEM under the Obama and Trump Administrations had sought to implement varying levels of stringent and costly standards under the existing federal financial assurance requirements, either through issuance and implementation of NTL #2016-N01 as was the case under the Obama Administration, or proposing rulemaking to revise the decommissioning and related financial assurance regulations as was the case under the Trump Administration. However, BOEM under the Biden Administration is expected to propose new financial assurance requirements that, if adopted as proposed, could increase our operating costs. See Part I, Item 1, *Business – Compliance with Governmental Regulations* for more discussion on financial assurance regulatory initiatives impacting the oil and natural gas industry that may be pursued under the Biden Administration. Additionally, 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 such future orders, BOEM could commence enforcement proceedings or take other remedial action, 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.

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.

In January 2021, President Biden suspended new oil and natural gas leases on federal lands and waters, including the OCS pending review and reconsideration of federal oil and gas leasing and permitting practices. While this suspension was challenged and enjoined in June 2021 by a federal district court, the Biden Administration is appealing the court decision. Additionally, regulatory agencies under the Biden Administration may issue new or amended rulemakings regarding deep water 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. The BSEE and the BOEM have over the past decade, primarily under the Obama Administration, imposed more stringent permitting procedures and regulatory safety and performance requirements with respect to new wells drilled in federal deepwater. While actions by BSEE or BOEM under the former Trump Administration sought to mitigate or delay certain of those more rigorous standards, the Biden Administration could reconsider rules and regulatory initiatives implemented under the Trump Administration and replace them with new, more stringent requirements and also provide more rigorous enforcement of existing regulatory requirements. Compliance with any added or more stringent Biden Administration regulatory requirements or enforcement initiatives and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans and possible additional regulatory initiatives could result in difficult and more costly actions and 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 United States Gulf of Mexico that could result in new, more restrictive requirements.

These regulatory actions, or any new rules, regulations, or legal or enforcement initiatives or controls that impose increased costs or 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, fines, or 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 – Compliance with Governmental Regulations* 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 are especially significant because our operations are concentrated in the Gulf of Mexico.

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.

Moreover, BSEE under the Biden Administration could also reconsider its current NTL on idle iron removal or existing idle iron-related regulations and establish new, more stringent decommissioning requirements on an expedited basis. 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 or increased 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. 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 will differ dramatically from our recorded estimate if we have a damaged platform.

Any additional requirements under BOEM’s formerly issued NTL #2016-N01, if it were re-issued and fully implemented, or in the event BOEM under the Biden Administration were to issue new, more stringent financial assurance guidance or requirements, would increase our operating costs and reduce the availability of surety bonds due to the increased demands for such bonds in a low-price commodity environment. In addition, increased demand for salvage contractors and equipment could result in increased costs for decommissioning activities, including plugging and abandonment operations. These items have, and may further, increase our costs and impact our liquidity adversely.

In addition, the U.S. Government imposes strict joint and several liability under the OCSLA on the various lessees of a federal oil and gas lease for lease obligations, including decommissioning activities, which means that any single co-lessee may be liable to the U.S. Government for the full amount of all of the multiple lessees' obligations under the lease. In certain circumstances, we also could be liable for accrued decommissioning liabilities on federal oil and gas leases that we previously owned and assigned to an unrelated third party should the assignee to whom we assigned the leases or any future assignee of those leases is unable to perform its decommissioning obligations (including payment of costs incurred by unrelated parties in decommissioning such lease facilities). For example, we have in the past received a demand for payment of decommissioning costs related to accrued liabilities for property interests that were sold several years prior. These indirect obligations would affect our costs, operating profits and cash flows negatively and could be material.

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 crude 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 on the way we can discharge 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.

We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. It is also possible that a portion of our oil and natural gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See *Business – Compliance with Government Regulations* under Part I, Item 1 in this Form 10-K for a more detailed explanation of regulations impacting our business.

Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to MPAs and endangered and threatened species.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit or other approval before drilling or other regulated activity commences; restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; limit or prohibit exploration or drilling activities on certain lands lying within wilderness, wetlands, MPAs and other protected areas or that may affect certain wildlife, including marine species and endangered and threatened species; and impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties; loss of our leases; incurrence of investigatory, remedial or corrective obligations; and the imposition of injunctive relief, which could prohibit, limit or restrict our operations in a particular area.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could incur strict joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and regardless of whether our operations met previous standards in the industry at the time they were conducted. Our permits require that we report any incidents that cause or could cause environmental damages.

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

Responses to the threat of climate change, including energy transition, could result in increased costs and reduced demand for the oil and natural gas we produce, which could have a material adverse effect on our business, results of operations, financial condition and cash flows while physical risks related to climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

The threat of climate change continues to attract considerable attention in the United States and foreign countries. As a result, 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 – Compliance with Environmental Regulations" 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. 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.

Increasing attention 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. Further, 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. Moreover, the increased competitiveness of alternative energy sources (such as wind, solar geothermal, tidal and biofuels) could reduce demand for the oil and natural gas we produce, which would lead to a reduction in our revenues.

For example, stockholders and bondholders currently invested in fossil fuel energy companies such as ours but concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices that favor "clean" power sources, such as wind and solar, making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made "net zero" carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and are taking steps to quantify and reduce those emissions. 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.

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, the Company's 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.

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.

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.

From time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and gas companies. Such 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 any series of preferred stock to elect directors under specified circumstances, if any, any action required or permitted to be taken by our stockholders must be effected at a duly called annual or special meeting of our stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders;
- 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 only be called by the Chairman of our board of directors, our President, or our board of directors pursuant to a resolution adopted by a majority of the total number of directors that we would have if there were no vacancies, or at least 30% of the voting power of all outstanding shares entitled to vote generally at the special meeting;
- 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 66 2/3% in voting power of the outstanding shares of our common stock entitled to vote thereon, voting together as a single class; and
- provide that our bylaws can be altered or repealed only by our board of directors.

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 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.

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, 2022, two of our fields located in the conventional shelf accounted for approximately 66.7% our proved reserves on an energy equivalent basis. The following table provides information for these fields:

	Proved Reserves as of December 31, 2022				
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Percent of Total Company Proved Reserves
Mobile Bay Properties	0.3	14.2	460.4	91.3	55.2 %
Ship Shoal 349 (Mahogany)	12.7	1.4	29.3	19.0	11.5 %

The Mobile Bay Properties (as defined below) and Ship Shoal 349 (Mahogany) (as defined below) 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. Following are descriptions of these areas of operations:

Mobile Bay Properties

A-I LLC and all of its 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." In 2021, we consolidated the Fairway field into the Mobile Bay Properties in conjunction with the sale of the Mobile Bay Properties to the Subsidiary Borrowers as described in *Financial Statements and Supplementary Data – Note 4 – Subsidiary Borrowers* under Part II, Item 8 in this Form 10-K.

We acquired our initial 64.3% working interest, along with operatorship, in the Fairway field and associated Yellowhammer gas processing plant, from Shell Offshore, Inc. in August 2011 and acquired the remaining working interest of 35.7% in September 2014. In August 2019, we acquired varied operated working interests in the other Mobile Bay Properties ranging from 25% to 100% in nine producing fields from Exxon (effective January 1, 2019), and we became the operator of the fields in December 2019. During September 2019 to December 2019, transitioning activities occurred to transfer operatorship of the Mobile Bay Properties from Exxon to W&T. During 2020, we completed the purchase of the remaining interest in two federal Mobile Bay fields from Chevron U.S.A. Inc. Cumulative field production for the combined Mobile Bay and Fairway properties through 2022 is approximately 854.7 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, 2022, 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,		
	2022	**2021**	**2020**
Net Sales:			
Oil (MBbls)	17	29	9
NGLs (MBbls)	941	998	1,167
Natural gas (MMcf)	30,052	32,940	34,793
Total oil equivalent (MBoe)	5,967	6,516	6,975
Average realized sales prices:			
Oil ($/Bbl)	$ 51.60	$ 27.49	$ 38.52
NGLs ($/Bbl)	35.45	30.84	10.34
Natural gas ($/Mcf)	7.45	3.92	2.08
Oil equivalent ($/Boe)	43.25	24.68	12.18
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 11.81	$ 7.34	$ 5.60

(1) Includes lease operating expenses and gathering and transportation 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"). Phillips Petroleum Company discovered the Ship Shoal 349. We initially acquired a 25% working interest in the field from BP Amoco in 1999. In 2003, we acquired an additional 34% working interest through a transaction with ConocoPhillips that increased our working interest to approximately 59%, and we became the operator of the field in December 2004. In early 2008, we acquired the remaining working interest from Apache Corporation and we now own a 100% working interest in this field except for an interest in one well owned by the Joint Venture Drilling Program. Cumulative field production through 2022 is approximately 61.4 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, 2022, 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, 2022	2021	2020
Net Sales:			
Oil (MBbls)	1,313	1,667	1,939
NGLs (MBbls)	104	88	148
Natural gas (MMcf)	1,827	2,565	3,015
Total oil equivalent (MBoe)	1,722	2,182	2,590
Average realized sales prices:			
Oil ($/Bbl)	$ 88.36	$ 65.27	$ 36.69
NGLs ($/Bbl)	40.50	36.85	14.46
Natural gas ($/Mcf)	7.15	4.00	1.92
Oil equivalent ($/Boe)	71.03	56.05	30.54
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 7.63	$ 6.60	$ 4.98

(1) Includes lease operating expenses and gathering and transportation 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, 2022, 2021 and 2020 are summarized below:

Classification of Proved Reserves (1)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	MMBoe	% of Total Proved	PV-10 (In millions)
December 31, 2022						
Proved developed producing	23.7	16.1	499.2	123.0	75 %	$ 2,280.8
Proved developed non-producing	7.4	1.5	76.8	21.8	13 %	457.6
Total proved developed	31.1	17.6	576.0	144.8	88 %	2,738.4
Proved undeveloped	9.5	1.3	58.6	20.5	12 %	390.2
Total proved	40.6	18.9	634.6	165.3	100 %	$ 3,128.6
December 31, 2021						
Proved developed producing	20.8	16.4	507.9	121.9	77 %	$ 1,185.3
Proved developed non-producing	6.8	1.4	41.3	15.1	10 %	222.9
Total proved developed	27.6	17.8	549.2	137.0	87 %	1,408.2
Proved undeveloped	9.6	1.3	58.4	20.6	13 %	213.7
Total proved	37.2	19.1	607.6	157.6	100 %	$ 1,621.9
December 31, 2020						
Proved developed producing	19.4	15.6	510.4	120.1	83 %	$ 573.0
Proved developed non-producing	4.6	0.9	39.8	12.1	8 %	73.7
Total proved developed	24.0	16.5	550.2	132.2	91 %	646.7
Proved undeveloped	8.2	0.9	19.1	12.2	9 %	94.2
Total proved	32.2	17.4	569.3	144.4	100 %	$ 740.9

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2022 were determined to be economically producible under existing economic conditions, which requires the use of the SEC pricing. Applying this methodology, the West Texas Intermediate ("WTI") crude oil average spot price of $94.14 per barrel and the Henry Hub natural gas average spot price of $6.36 per million British Thermal Unit were utilized as the referenced price and after adjusting for quality, transportation, fees, energy content and regional price differentials, the average adjusted product prices were $91.50 per barrel for oil, $41.92 per barrel for NGLs and $6.85 per Mcf for natural gas. In determining the estimated realized price for NGLs, a ratio was computed for each field of the NGLs realized price compared to the crude oil realized price. Then, this ratio was applied to the crude 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 escalations.

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,		
	2022	2021	2020
Present value of estimated future net revenues (PV-10)	$ 3,128.6	$ 1,621.9	$ 740.9
Present value of estimated ARO, discounted at 10%	(271.5)	(241.1)	(204.2)
PV-10 after ARO	2,857.1	1,380.8	536.7
Future income taxes, discounted at 10%	(594.1)	(224.8)	(43.0)
Standardized measure	$ 2,263.0	$ 1,156.0	$ 493.7

Changes in Proved Reserves

The following table discloses our estimated changes in proved reserves during the year ended December 31, 2022:

	MMBoe
Proved reserves at December 31, 2021	157.6
Reserves additions (reductions):	
Revisions[1]	16.3
Extensions and discoveries	0.0
Purchases of minerals in place	6.0
Production	(14.6)
Net reserve additions (reductions)	7.7
Total proved reserves at December 31, 2022	165.3

(1) Net revisions of 16.3 MMBoe are primarily attributable to higher commodity prices.

See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2022. See *Financial Statements and Supplementary Data– Note 19 – 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, 2022 are calculated based upon SEC mandated 2022 unweighted average first-day-of-the-month crude 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 2022 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.

Development of Proved Undeveloped Reserves

Our PUDs were estimated by NSAI, our independent petroleum consultant. Future development costs associated with our PUDs at December 31, 2022 were estimated at $429.5 million.

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

	December 31,		
	2022	2021	2020
Proved undeveloped reserves, beginning of year	20.6	12.2	23.6
Transfers to proved developed reserves	—	—	—
Revisions of previous estimates	(0.1)	8.4	(11.4)
Extensions and discoveries	—	—	—
Purchase of minerals in place	—	—	—
Sales of minerals in place	—	—	—
Proved undeveloped reserves, end of year	20.5	20.6	12.2

Activity related to PUDs – Net PUD revisions in 2022, 2021 and 2020 were primarily due to revisions to previous estimates that are based on both technical revisions and revisions due to changes in SEC pricing at our Ship Shoal 028 and Ship Shoal 349 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
2023	1	14 %
2024	3	12 %
2025	2	20 %
2026	5	54 %
Total	11	100 %

We believe that we will be able to develop all but 2.5 MMBoe (approximately 12%) of the total 20.5 MMBoe classified as PUDs at December 31, 2022, within five years from the date such PUDs were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field ("Matterhorn") and Viosca Knoll 823 ("Virgo") deepwater fields where future development drilling has been planned as sidetracks of existing wellbores due to conductor slot limitations and rig availability. Two sidetrack PUD locations, one each at Matterhorn 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 2024.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2022 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 crude 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.

Acreage

The following table summarizes our leasehold at December 31, 2022. Deepwater refers to acreage in over 500 feet of water:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	389,978	321,261	67,604	62,342	457,582	383,603
Deepwater	141,929	56,540	17,280	11,520	159,209	68,060
Alabama State Waters	8,037	5,144	—	—	8,037	5,144
Total	539,944	382,945	84,884	73,862	624,828	456,807

Our net acreage increased 44,746 net acres (11%) from December 31, 2021 due to the addition of new leases and acquisitions occurring in 2022.

Approximately 83.8% 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
Expire 2023	23,906	33%
Expire 2024	17,122	23%
Expire 2025	11,313	15%
Expire 2026	5,760	8%
Expire thereafter	15,761	21%
Total	73,862	100%

In making decisions regarding drilling and operations activity for 2023 and beyond, we give consideration to undeveloped leasehold 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. The following table sets forth our drilling activity for completed wells on a gross basis:

	Completed		
	2022	2021	2020
Conventional shelf	1	—	—
Deepwater	1	—	—
Wells operated by W&T	1	—	—

Development and Exploration

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

	Year Ended December 31,		
	2022	2021	2020
Development Wells Completed:			
Gross wells	—	—	—
Net wells	—	—	—
Exploration Wells Completed:			
Gross wells	2	—	—
Net wells	0.6	—	—

During 2020, we drilled one well, which we completed in March 2022. During 2021, we participated in the drilling of an exploration well which was non-commercial. We had a 25% working interest in that well which was abandoned in 2022. 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

The following presents our ownership interest at December 31, 2022 in our productive oil and natural gas wells. A net well represents our fractional working interest of a gross well in which we own less than all of the working interest:

	Oil Wells (1)		Gas Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	116.0	105.8	85.0	78.6	201.0	184.4
Non-operated	33.0	5.0	3.0	0.5	36.0	5.5
Total offshore wells	149.0	110.8	88.0	79.1	237.0	189.9

(1) Includes 8 gross (5.9 net) oil wells with multiple completions.

(2) Includes 2 gross (2.0 net) gas wells with multiple completions.

Production

For the years 2022, 2021 and 2020, our net daily production averaged 40,067 Boe, 38,118 Boe, and 42,046 Boe, respectively. Production increased in 2022 from 2021 primarily due to acquisitions offset by well maintenance events throughout the year. 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.

The following presents historical information about our produced oil, NGLs and natural gas volumes from all of our producing fields over the past three years:

	Year Ended December 31,		
	2022	2021	2020
Net Sales:			
Oil (MBbls)	5,602	4,998	5,629
NGLs (MBbls)	1,554	1,450	1,696
Natural gas (MMcf)	44,808	44,790	48,384
Total oil equivalent (MBoe)	14,624	13,913	15,389

Item 3. ***Legal Proceedings***

Appeal with ONRR. In 2009*,* W&T 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 in 2010*,* ONRR notified the Company that they had disallowed approximately $4.7 million of the reductions taken. The Company recorded a reduction to other revenue in 2010 to reflect this disallowance with the offset to a liability reserve; however, the Company disagrees with the position taken by the ONRR. W&T filed an appeal with the ONRR, which ultimately led to the Company posting a bond in the amount of $7.2 million and cash collateral of $6.9 million with the surety in order to appeal the Interior Board of Land Appeals decision. The cash collateral held by the surety was subsequently returned to the Company during the first quarter of 2020*.* 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. W&T 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. In compliance with the ONRR's request for W&T to post surety, the sum of the bond posted is currently $8.5 million.

Civil Penalty Assessments. In January 2021, W&T executed a Settlement Agreement with BSEE which resolved nine pending civil penalties issued by BSEE. The civil penalties pertained to Incidents of Non-Compliance ("INC") issued by BSEE alleging regulatory non-compliance at separate offshore locations on various dates between July 2012 and January 2018, with the proposed civil penalty amounts totaling $7.7 million. Under the Settlement Agreement, W&T will pay a total of $720,000 in three annual installments. The first, second and final installments were paid in March 2021, March 2022 and February 2023, respectively. In addition, W&T committed to implement a Safety Improvement Plan with various deliverables due, which have all been timely satisfied.

AAIT Litigation. In August 2022, the Company's primary information technology service provider, All About IT, Inc. ("AAIT"), notified the Company of its intention to cease providing services to the Company by September 2, 2022. Following such notification, the Company began the process of moving certain of these services within the Company and transitioning the remaining services to new service providers. On August 19, 2022, the Company filed in the District Court of Harris County, Texas a petition for a temporary restraining order, temporary injunction, and permanent injunction seeking, among other things, to restrain AAIT from ceasing to provide services to the Company until the transition process is complete. On September 14, 2022, AAIT removed the matter to the United States District Court for the Southern District of Texas. On September 16, 2022, the Company and AAIT mutually agreed to the terms of an agreed order of the court providing for a temporary injunction for a period of a minimum of 60 days from the date of the order and up to a maximum of 120 days at the Company's option, during which AAIT would continue to provide information technology services to the Company and assist with the transition process. By agreement of the parties, the agreed order also provided for the appointment of Hon. Gregg J. Costa (Ret.) as an independent adjudicator to assist in adjudicating ongoing disputes between the parties. As of December 31, 2022, the Company has substantially completed the transition process and the Company no longer has a material relationship with AAIT.

Other Claims. We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. We are 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 we can give no assurance about the outcome of pending legal and federal or state administrative proceedings and the effect such an outcome may have on us, we believe 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 our consolidated financial position, results of operations or liquidity.

See *Financial Statements and Supplementary Data – Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information on the matters described above.

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

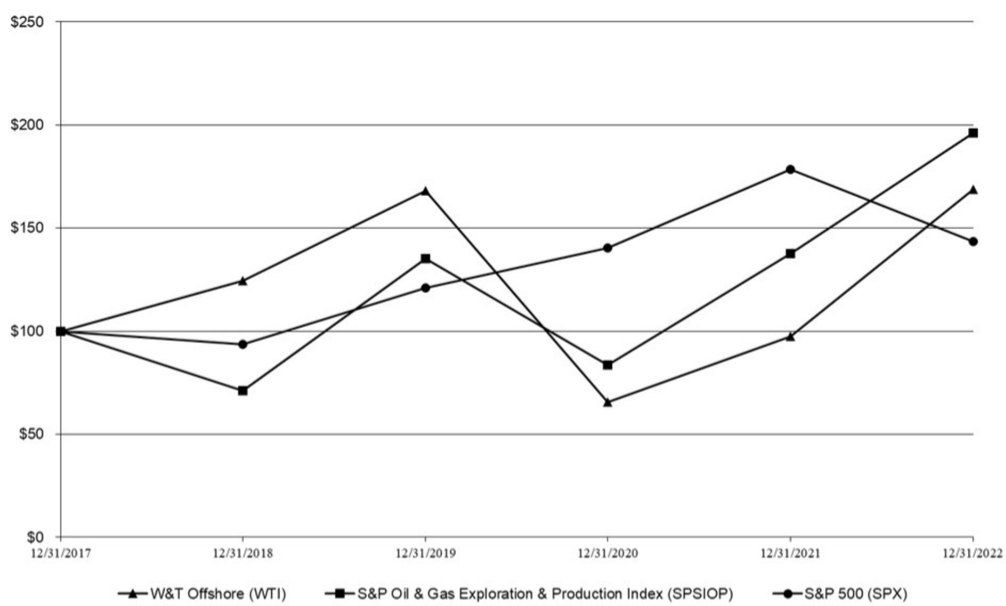
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of March 1, 2023, there were 180 registered holders of our common stock.

Dividends

During 2022 and 2021, no dividends were paid as dividend payments have been suspended. Our Board of Directors decides the timing and amounts of any dividends for the Company. Dividends are subject to periodic review of the Company's performance, which includes the current economic environment and applicable debt agreement restrictions. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 and *Financial Statements and Supplementary Data – Note 2 –Debt* under Part II, Item 8 in this Form 10-K for more information regarding covenants related to dividends in our debt agreements.

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

For the year ended December 31, 2022, we did not purchase any of our equity securities.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2022 that we have not previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

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 II, Item 8 *Financial Statements and Supplementary Data* in this 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 of this Annual Report generally discusses 2022 and 2021 items and year-to-year comparisons between 2022 and 2021. Discussions of 2020 items and year-to-year comparisons between 2021 and 2020 that are not included in this Annual Report are incorporated by reference to Part II, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* of the Company's Annual Report on Form 10-K for the year ended December 31, 2021.

Business Overview

W&T is 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, 2022, we held working interests in 47 offshore producing fields in federal and state waters (45 producing fields and 2 capable of producing). Our interest in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. and our wholly-owned subsidiaries, Aquasition LLC, Aquasition II LLC, and W & T Energy VI LLC, Delaware limited liability companies 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. We strive to operate within cash flow to reduce debt, optimize the balance sheet and maintain financial flexibility. A majority of our daily production is derived from wells we operate.

Outlook

During 2022, commodity prices experienced significant improvement, due to a confluence of factors that have provided positive developments to the overall pricing environment when compared to 2021. While the current outlook for commodity prices is favorable and our operations are no longer significantly impacted by COVID-19, other global factors could adversely impact our operations, and commodity prices could significantly decline from current levels.

Our cash flows are materially impacted by the prices of commodities we produce (crude oil and natural gas, and the NGLs extracted from the natural gas). In addition, the prices of goods and services used in our business can vary and impact our cash flows. During 2022, average realized commodity prices increased from those we experienced during 2021 and 2020. Our margins in 2022 increased from 2021 primarily due to higher average realized commodity prices, partially offset by higher operating expenses. We measure margins using Adjusted EBITDA which we define net (loss) income (loss) before income tax expense (benefit), net interest expense, and depreciation, depletion, amortization and accretion, the unrealized commodity derivative gain or loss and the effects derivative premium payments, allowance for credit losses, write off of debt issuance costs, non-cash incentive compensation, non-recurring IT transition costs, release of restricted funds, non-ARO P&A costs, and other miscellaneous costs as a percent of revenue, which is not a financial measurement under GAAP. We have historically increased our reserves and production through acquisitions, our drilling program, and other projects that optimize production on existing wells. Our production increased 5.1% in 2022 from the prior year. Our proved reserves increased by 7.7 MMBoe in 2022, primarily due to the significant increase in commodity prices in 2022 as compared to 2021.

We continually monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2023 plans. See *Liquidity and Capital Resources* under this Item 7 in this Form 10-K for additional information.

Recent Developments

Issuance of 11.75% Senior Second Lien Notes due 2026 – On January 27, 2023, we issued $275.0 million of 11.75% Senior Second Lien Notes due 2026. The 11.75% Senior Second Lien Notes were issued at par and have a maturity date of February 1, 2026. See *Financial Statements and Supplementary Data –Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

Redemption of 9.75% Senior Second Lien Notes due 2023 – On February 8, 2023, we redeemed all of the 9.75% Senior Second Lien Notes outstanding at a redemption price of 100.000%, plus accrued and unpaid interest to the redemption date. As of December 31, 2022, there was $552.5 million of aggregate principal outstanding. The Company used the net proceeds of $270.8 million from the issuance of the 11.75% Senior Second Lien Notes and cash on hand of $296.1 million to fund the redemption. See *Financial Statements and Supplementary Data –Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

Reaffirmation of Credit Agreement. On February 8, 2023, the Company provided notice of the redemption of the existing 9.75% Senior Second Lien Notes and the issuance of the 11.75% Senior Second Lien Notes to Alter Domus (US) LLC and Calculus pursuant to the terms of the Credit Agreement, which reaffirmed the Credit Agreement's maturity date of January 3, 2024.

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

Asset Acquisitions – During the first and second quarters of 2022, the Company acquired the Ship Shoal 230, South Marsh Island 27/Vermilion 191, and South Marsh Island 73 fields. This transaction is described in more detail under *Financial Statements and Supplementary Data – Note 6 – Acquisitions*, under Part II, Item 8, of this Annual Report.

Hurricanes and Severe Weather – We did not experience any significant deferred production related to named storms or other severe weather events during the year ended December 31, 2022. During 2021, some of our production from the Gulf of Mexico was impacted due to precautionary shut-ins of facilities and evacuations primarily associated with Hurricane Ida. While Company assets and infrastructure did not suffer significant damage during the storm, unplanned costs of $5.4 million for minor repairs and restoring production, as well as evacuating employees and contractors, were incurred as a result of the hurricane and reflected in lease operating expense. For the year ended December 31, 2021, we estimate deferred production related to these storms was approximately 0.8 MMBoe per day. See Part I, Item 1, *Business– Insurance Coverage* in this Form 10-K for additional information.

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 (crude oil and natural gas, and the NGLs extracted from the natural gas). Our realized sales prices received for our crude 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. In addition, the prices of goods and services used in our business can vary and impact our cash flows. 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.

In addition to such industry-specific risks, the global public health crisis associated with COVID-19 has created uncertainty for global economic activity since March 2020. Since 2021, increased mobility, deployment of vaccines and other factors have resulted in increased oil demand and commodity prices. However, new variants of the virus continue to emerge and it is difficult to assess if such variants will cause meaningful disruptions in economic activity across the world and if there will be any significant impacts in demand for energy because of the ongoing pandemic.

A high level of uncertainty remains regarding the volatility of energy supply and demand. In October 2022 OPEC Plus announced a production cut of approximately two million barrels per day. These shifts in OPEC Plus production levels as well as the Russia-Ukraine war and related sanctions, which began in the first quarter of 2022, continue to contribute to a high level of uncertainty surrounding energy supply and demand putting additional upward pressure on commodity prices. As a result, governmental authorities have implemented, and are expected to continue to implement, measures to address rising crude oil prices, including releasing emergency oil reserves.

WTI is frequently used to value domestically produced crude oil, and our crude oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. NYMEX WTI daily spot crude oil prices averaged $94.90 per barrel during 2022, up from $68.14 barrel during 2021. The U.S. Energy Information Administration ("EIA") in their Short-Term Energy Outlook issued in February 2023 projects average crude oil prices for WTI to decrease to approximately $77.84 per barrel in 2023 and further decrease in 2024 to approximately $71.57 per barrel. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. NYMEX Henry Hub spot prices averaged $6.45 per MMBtu during 2022, up from $3.89 per MMBtu during 2021. The EIA projects average natural gas prices for Henry Hub to decrease to approximately $3.40 per MMBtu in 2023 and increase in 2024 to approximately $4.04 per MMBtu. Global oil production is forecasted to outpace global oil consumption during 2023 resulting in rising global oil inventories. Oil market balances are subject to significant uncertainties which could keep oil prices volatile.

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 10 – Derivative Financial Instruments*, under Part II, Item 8, of this Annual Report for additional information regarding our commodity derivative positions as of December 31, 2022.

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 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. The annual rate of inflation in the United States was at 6.5% as measured in December 2022 by the Consumer Price Index. This is down from the June 2022 peak of 9.1%. However, it is still higher than historical averages. In addition, the Federal Reserve has tightened monetary policy by approving a series of increases to the Federal Funds Rate and signaled that the Federal Reserve would continue to take necessary action 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 hurt our business.

As a result of these factors, we cannot accurately predict future commodity prices and, 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.

Inflation Reduction Act of 2022 – On August 16, 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 Department of the Interior ("DOI") to accept the highest bids received for Lease Sale 257 which was vacated by US District Court for the District of Columbia in January 2022 and move forward with Lease Sales 259 and 261 in the Gulf of Mexico by March 31, 2023 and September 30, 2023, respectively, notwithstanding the June 30, 2022 expiration of the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program.

The IRA ties the issuance of offshore leases for wind development by the federal government to requirements to offer for sale federal oil and gas leases for a 10-year period of time. The IRA requires the federal government to offer for sale a minimum of 60 million acres for offshore oil and gas leases during the one-year period immediately preceding granting an offshore wind lease on the U.S. Outer Continental Shelf.

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 imposes a methane emissions charge. 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, natural gas and NGL prices may subsequently increase the ceiling. We perform this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, we utilize SEC Pricing when performing the ceiling test. At December 31, 2022, the Company's ceiling test computation was based on SEC pricing of $91.50 per Bbl of oil, $41.92 per Bbl of NGLs and $6.85 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 unplanned production downtime caused by events outside of our control and create uncertainties in our financial condition, cash flow and results of operations. Such events include third party downtime associated with non-operated properties and the transportation, gathering or processing of production and weather events. For the year ended December 31, 2022, we estimate deferred production was approximately 2,314 MBoe, primarily due to unplanned well maintenance.

Hurricane and Severe Weather Events – Since our operations are in the Gulf of Mexico, we are particularly vulnerable to the effects of hurricanes on production. We normally obtain insurance to reduce, but not totally mitigate, our financial exposure risk; however, affordable insurance coverage for property damage to our facilities for hurricanes is not assured. See Item 1 *Business – Insurance Coverage* under Part I in this Form 10-K for additional information. Significant hurricane impacts could include reductions and/or deferrals of future oil and natural gas production and revenues, increased lease operating expense for evacuations and repairs and possible acceleration of plugging and abandonment costs.

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

BOEM Matters – 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, 2022, the Company is in compliance with its financial assurance obligations to BOEM and has 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 BOEM as BOEM continues to reevaluate its requirements for financial assurance. For more information on the BOEM and financial assurance obligations to that agency, see *Business – Compliance with Government Regulations – Decommissioning and financial assurance requirements* 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 2022 or 2021, 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, 2022 Compared to Year Ended December 31, 2021

Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs. Our oil, natural gas and NGL revenues do not include the effects of derivatives, which are reported in "Derivative loss (gain)" in our Consolidated Statements of Operations. The following table presents our sources of revenue as a percentage of total revenue:

	Year Ended December 31,	
	2022	2021
Oil	56.9 %	59.1 %
NGLs	6.2 %	7.9 %
Natural gas	35.2 %	31.1 %
Other	1.7 %	1.9 %

The information below provides a discussion of, and an analysis of significant variance in, our oil, natural gas and NGL revenues, production volumes and average sales prices for the years ended December 31, 2022 and 2021 (in thousands):

	Year Ended December 31, 2022	2021	Change
Revenues:			
Oil	$ 524,274	$ 329,557	$ 194,717
NGLs	56,964	44,343	12,621
Natural gas	323,831	173,749	150,082
Other	15,928	10,361	5,567
Total revenues	$ 920,997	$ 558,010	$ 362,987
Production Volumes:			
Oil (MBbls)	5,602	4,998	604
NGLs (MBbls)	1,554	1,450	104
Natural gas (MMcf)	44,808	44,790	18
Total oil equivalent (MBoe)	14,624	13,913	711
Average daily equivalent sales (Boe/day)	40,067	38,118	1,949
Average realized sales prices:			
Oil ($/Bbl)	$ 93.59	$ 65.94	$ 27.65
NGLs ($/Bbl)	36.66	30.59	6.07
Natural gas ($/Mcf)	7.23	3.88	3.35
Oil equivalent ($/Boe)	61.89	39.36	22.53
Oil equivalent ($/Boe), including realized commodity derivatives[1]	59.15	32.89	26.26

(1) Excludes the effects of premium amortization and write-offs.

Changes in average sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2022 and 2021 (in thousands):

	Price	Volume	Total
Oil	$ 154,890	$ 39,827	$ 194,717
NGLs	9,422	3,199	12,621
Natural gas	150,011	71	150,082
	$ 314,323	$ 43,097	$ 357,420

Realized Prices on the Sale of Oil, NGLs and Natural Gas – Our average realized crude oil sales price differs from the WTI benchmark average crude price due primarily to premiums or discounts, crude oil quality adjustments, and volume weighting (collectively referred to as differentials). Crude oil quality adjustments can vary significantly by field as a result of quality and location. For example, crude oil from our East Cameron 321 field normally receives a positive quality adjustment, whereas crude oil from our Ship Shoal 349 field normally receives a negative quality adjustment. All of our crude oil is produced offshore in the Gulf of Mexico and is primarily characterized as Poseidon, Light Louisiana Sweet ("LLS"), and Heavy Louisiana Sweet ("HLS"). Similar to crude oil prices, the differentials for our offshore crude oil have also experienced volatility in the past. The monthly average differentials of WTI versus LLS and HLS for 2022 increased on average by approximately $0.43 - $0.75 per barrel compared to 2021 for these types of crude oils with LLS and HLS having positive differentials as measured on an index basis. The monthly average differentials of WTI versus Poseidon decreased by $1.91 per barrel compared to 2021 with Poseidon having a negative differential.

Two major components of our NGLs, ethane and propane, typically make up approximately 70% of an average NGL barrel. During 2022, average prices for domestic ethane increased by 55.6% and average domestic propane prices increased by 5.6% from 2021 as measured using a price index for Mount Belvieu. The changes in the average price for other domestic NGLs components in 2022 ranged from an increase of 11.4% to 22.5% year-over-year.

The actual prices we realize from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. Currently, the sales points of our gas production are generally within close proximity to the Henry Hub which creates a minimal differential in the prices we receive for our production versus average Henry Hub prices.

Oil, NGLs, and Natural Gas Volumes – Production volumes increased by 711 MBoe to 14,624 MBoe primarily due to the acquisition of the Ship Shoal 230, South Marsh Island 27/Vermilion 191, and South Marsh Island 73 fields during the first and second quarters of 2022. The increase in production from these asset acquisitions was offset by downtime related to field and well maintenance events, primarily at Mobile Bay and other OCS fields. Deferred production for 2022 related to these events collectively resulted in deferred production of 2.3 MMBoe, compared to 2.2 MMBoe in 2021.

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:

	Year Ended December 31,		
	2022	2021	Change
Operating expenses:			
Lease operating expenses	$ 224,414	$ 174,582	$ 49,832
Gathering, transportation and production taxes	35,128	27,919	7,209
Depreciation, depletion, amortization and accretion	133,630	113,447	20,183
General and administrative expenses	73,747	52,400	21,347
Total operating expenses	$ 466,919	$ 368,348	$ 98,571
Average per Boe ($/Boe):			
Lease operating expenses	$ 15.35	$ 12.55	$ 2.80
Gathering, transportation and production taxes	2.40	2.00	0.40
DD&A	9.14	8.15	0.99
G&A expenses	5.04	3.77	1.27
Operating expenses	$ 31.93	$ 26.47	$ 5.46

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, facilities repairs and maintenance expenses, and hurricane repair 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 $49.8 million to $224.4 million in 2022 compared to $174.6 million in 2021. On a per Boe basis, lease operating expenses increased to $15.35 per Boe during 2022 compared to $12.55 per Boe during 2021. On a component basis, base lease operating expenses increased $35.1 million, workover expenses increased $8.2 million and facilities maintenance expenses increased $11.8 million. These increases were partially offset by a decrease of $5.4 million in hurricane repairs.

Expenses for direct labor, materials, supplies, repair and third party costs comprise the most significant portion of our base lease operating expense. Base lease operating expenses increased primarily due to increased expenses related to the Ship Shoal 230, South Marsh Island 27/Vermilion 191, and South Marsh Island 73 fields acquired during the first half of 2022, increased labor costs, and increased insurance expense.

Workovers and facilities maintenance expenses consist of costs associated with major remedial operations on completed wells to restore, maintain or improve the well's production. Since these remedial operations are not regularly scheduled, workover and maintenance expense are not necessarily comparable from period to period. Lastly, during the year ended December 31, 2021 we incurred $5.4 million in expenses related to repairs associated with hurricanes that we did not incur during the year ended December 31, 2022.

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 increased to $35.1 million in 2022 compared to $27.9 million in 2021, primarily due to a new transportation contract related to the properties acquired in the first half of 2022. Additionally, the increase in realized natural gas and NGL prices along with an increase in oil, NGL and natural gas production during 2022 caused gathering, transportation and production taxes to increase.

Depreciation, depletion, amortization and accretion – Depreciation, depletion and amortization expense 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. Accretion expense is the expensing of the changes in value of our asset retirement obligations 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. DD&A, which includes accretion for ARO, increased to $9.14 per Boe in 2022 from $8.15 per Boe in 2021. On a nominal basis, DD&A increased to $133.6 million in 2022 from $113.4 million in 2021. The DD&A rate per Boe increased mostly as a result of increases in the capital expenditures and future development costs included in the depreciable base associated with an increase in economic proved undeveloped wells due to higher oil and gas prices compared to the smaller increase in proved reserves over the comparable prior year period.

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, equity based compensation expense, audit and other fees for professional services and legal compliance. For 2022, G&A expenses were $73.7 million compared to $52.4 million in 2021. The increase is primarily due to non-recurring professional services costs incurred during the second half of 2022 after a review of processes and controls within our information technology department, including additional non-recurring expenses associated with the process of transitioning substantially all of our information technology infrastructure and related services internally or to other providers. Further, we have incurred additional legal expenses in conjunction therewith. Additionally, during 2022 we incurred increased costs related to salaries, benefits and incentive compensation as a result of the higher grant date fair values of stock awards granted during 2022 as compared to the value of awards granted in 2021, the lack of an employee retention credit provided under the CARES Act (which was received in 2021 and not received in 2022) and in response to wage and price inflation as compared to 2021 and as a result of inflation.

Other Income and Expense

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

	Year Ended December 31,		
	2022	2021	Change
		(In thousands)	
Other income and expenses:			
Derivative loss	$ 85,533	$ 175,313	$ (89,780)
Interest expense, net	69,441	70,049	(608)
Other expense (income), net	14,295	(6,165)	20,460
Income tax expense (benefit)	53,660	(8,057)	61,717

Derivative loss – During the year ended December 31, 2022, the $85.5 million derivative loss recorded for crude oil and natural gas derivative contracts consists of $125.1 million of realized losses on settled contracts and premium payments 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. During the year ended December 31, 2021, the $175.3 million derivative loss recorded for crude oil and natural gas derivative contracts consisted of $92.6 million in realized losses on settled contracts and premium payments and $82.8 million of unrealized losses from the decrease in the fair value of open oil and natural gas contracts.

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 (loss) based on fluctuations in market prices for natural gas. As of December 31, 2022, we do not have any open oil contracts. See *Financial Statements and Supplementary Data – Note 10 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense, net – We finance a portion of our working capital requirements, capital expenditures and acquisitions with term-based debt and, from time to time, borrowings under our Credit Agreement. As a result, we may incur interest expense that is affected by both fluctuations in interest rates and the amount of debt outstanding. Interest expense includes interest incurred under our debt agreements, the amortization of deferred financing costs (including origination and amendment fees), commitment fees, performance bond premiums and annual agency fees. Interest expense is presented net of any interest income we may receive. Interest expense, net, was $69.4 million in 2022, decreasing $0.6 million from $70.0 million in 2021. The decrease is primarily due to an increase in interest income between the two periods offset by higher interest expense related to the full year of the Term Loan payments. 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 (income), net – During the year ended December 31, 2022, other expense, net, was $14.3 million, compared to $6.2 million of other income, net, for 2021. During 2022, other expense primarily consists of additional expenses for net abandonment obligations pertaining to a number of legacy Gulf of Mexico properties, partially offset by non-recurring adjustments. For 2021, the amount primarily consists of other income related to the release of restrictions on the Black Elk Escrow fund, partially offset by expenses for net abandonment obligations pertaining to a number of legacy Gulf of Mexico properties and the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program. See *Financial Statements and Supplementary Data – Note 9 – Restricted Deposits for ARO* in Part II, Item 8 in this Form 10-K for additional information regarding the release of the Black Elk Escrow restrictions. See *Financial Statements and Supplementary Data – Note 18 – Contingencies* in Part II, Item 8 in this Form 10-K for additional information regarding the asset retirement obligations recorded for legacy properties.

Income tax expense (benefit) – Our income tax expense for 2022 was $53.7 million, and the income tax benefit for 2021 was $8.1 million. For 2022 and 2021, the annual effective tax rate was 18.8% and 16.3%, respectively, and the rates differed from the federal statutory rate of 21% primarily due to adjustments in the valuation allowance and the impact of state income taxes.

During 2022, our valuation allowance decreased $9.0 million primarily due to the utilization of part of our disallowed interest expense carryover. 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 our deferred tax assets, we consider 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 our future taxable income are consistent with the plans and estimates used to manage our business. The Company showed positive income in 2022 and continues to project similar results into the future. Based on this, we 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). As of December 31, 2022, the Company's valuation allowance was $15.3 million.

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 AROs. 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.

The primary sources of our liquidity are cash from operating activities and borrowings under our Credit Agreement. As of December 31, 2022, we had $461.4 million of available cash and $50.0 million available under our Credit Agreement, based on a borrowing base of $50.0 million. Additionally, we believe our access to the equity markets from our "at-the-market" equity offering program ("ATM Program"), our reserve based lending currently available under our Credit Agreement, along with our cash position, will provide us with additional liquidity to continue our growth to take advantage of the current commodity environment. During the year ended December 31, 2022, we 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.

As of December 31, 2022, we had outstanding $552.5 million principal of 9.75% Senior Second Lien Notes. On January 27, 2023, we issued $275.0 million of 11.75% Senior Second Lien Notes. The 11.75% Senior Second Lien Notes were issued at par and have a maturity date of February 1, 2026. On February 8, 2023, we redeemed all of the 9.75% Senior Second Lien Notes outstanding at a redemption price of 100.000%, plus accrued and unpaid interest to the redemption date. The Company used the net proceeds of $270.8 million from the issuance of the 11.75% Senior Second Lien Notes and cash on hand of $296.1 million to fund the redemption. See *Financial Statements and Supplementary Data –Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

We believe that we will have adequate liquidity from cash flow from operations to fund our capital expenditure plans for 2023, fund our ARO spending for 2023 and fulfill our various other obligations. Our preliminary capital expenditure budget for 2023 has been established in the range of $90.0 million to $110.0 million, which excludes acquisitions. In our view of the outlook for 2023, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2023 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 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.

Sources and Uses of Cash

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

	Year Ended December 31, 2022	2021	Change
		(In thousands)	
Operating activities	$ 339,530	$ 133,668	$ 205,862
Investing activities	(95,080)	(27,444)	(67,636)
Financing activities	(28,892)	100,266	(129,158)

Operating activities – Net cash provided by operating activities for 2022 was $339.5 million, increasing $205.9 million from 2021. The change between periods is primarily due to increased realized prices for crude oil, NGLs and natural gas in addition to increased volumes, decreased derivative settlement payments and derivative loss, and increased spending for ARO activities. Our combined average realized sales price per Boe increased 57.2% in 2022, which caused crude oil, NGLs and natural gas revenues to increase $314.3 million. In addition, increases of 5.1% in overall production volumes caused crude oil, NGLs and natural gas revenues to increase by $43.1 million.

These increases in operating cash flow were partially offset by (i) ARO settlements which decreased operating cash flows by $76.2 million as compared to $27.3 million during 2021; (ii) changes in operating assets and liabilities (excluding ARO settlements) which decreased operating cash flows by $7.2 million as compared to an increase of $33.7 million for the year ended December 31, 2021, primarily related to higher oil and natural gas receivables balances due to higher realized prices combined with lower payables and accrued liabilities balances.

Investing activities – Net cash used in investing activities increased $67.6 million for the year ended December 31, 2022 as compared to the year ended December 31, 2021. The increase was primarily due to the acquisition of properties for $51.5 million along with other increases in capital spending during the year ended December 31, 2022 compared to 2021. See *Financial Statements and Supplementary Data - Note 6 – Acquisitions* under Part II, Item 8 in this Form 10-K for additional information. There were no asset sales of significance in 2022 or 2021. See discussion in *Capital Expenditures* below.

Financing activities – During the year ended December 31, 2022, net cash used in financing activities was $28.9 million, primarily due to four quarters of principal payments on the Term Loan offset by net proceeds received from the sales of equity securities under our ATM Program. During the year ended December 31, 2021, net cash provided by financing activities was $100.3 million which included the proceeds from the Term Loan of $206.8 million, offset by $24.1 million of principal payments on the Term Loan and repayment of $80.0 million of borrowings under the Credit Agreement. See *Financial Statements and Supplementary Data - Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K for additional information regarding our ATM Program.

Derivative financial instruments – From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas. See *Financial Statements and Supplementary Data – Note 10 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information about our derivative activities. The following table summarizes the historical results of our hedging activities:

	Year Ended December 31,	
	2022	2021
Crude Oil ($/Bbl):		
Average realized sales price, before the effects of derivative settlements	$ 93.59	$ 65.94
Effects of realized commodity derivatives	(12.35)	(10.44)
Average realized sales price, including realized commodity derivatives	$ 81.24	$ 55.50
Natural Gas ($/Mcf)		
Average realized sales price, before the effects of derivative settlements	$ 7.23	$ 3.88
Effects of realized commodity derivatives(1)(2)	0.65	(0.84)
Average realized sales price, including realized commodity derivatives	$ 7.88	$ 3.04

(1) The year ended December 31, 2022 includes the effect of the $138.0 million realized gain related to the monetization of certain natural gas call contracts through restructuring of strike prices.

(2) Excludes the effects of premium amortization.

Income taxes – As of December 31, 2022, we have current income taxes payable of $0.4 million. During 2022, we did not receive any income tax refunds. For 2022, we made $8.2 million in income tax payments.

Dividends – During 2022, 2021 and 2020, we did not pay any dividends and a suspension of dividends remains in effect.

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 crude 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:

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Exploration(1)	$ 13,339	$ 18,273
Development(1)	20,390	9,478
Acquisitions of interests	51,474	661
Seismic and other	7,903	4,311
Investments in oil and gas property/equipment – accrual basis	$ 93,106	$ 32,723

(1) Reported geographically in the subsequent table.

The following table presents our exploration and development capital expenditures geographically:

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(In thousands)	
Conventional shelf [1]	$ 17,264	$ 7,872
Deepwater	16,465	19,879
Exploration and development capital expenditures – accrual basis	$ 33,729	$ 27,751

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

The capital expenditures reported in the above two tables are included within *Oil and natural gas properties and other, net* on the Consolidated Balance Sheets. The capital expenditures reported within the Investing section of the Consolidated Statements of Cash Flows include adjustments for payments related to capital expenditures.

Drilling Activity – We did not drill any wells during the year ended December 31, 2022. During the year ended December 31, 2022, we completed the East Cameron 349 B-1 well ("Cota"). The Cota well is in the Monza Joint Venture Drilling Program. See *Financial Statements – Note 6 –Joint Venture Drilling Program* Part II, Item 8 in this Form 10-K for additional information regarding Monza. See *Properties – Drilling Activity* under Part I, Item 2 of this Form 10-K for drilling activity information.

See *Properties – Development of Proved Undeveloped Reserves* under Part I, Item 2 of this Form 10-K for a discussion on activity related to proved undeveloped reserves.

Acquisitions – As described *Financial Statements and Supplementary Data - Note 6 - Acquisitions* under Part II, Item 8 in this Form 10-K, the Company acquired the working interest 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 on February 1, 2022 and April 1, 2022. After normal and customary post-effective date adjustments (including net operating cash flow attributable to the properties from the effective date to the respective close date), cash consideration of approximately $34.0 million and $17.5 million was paid to the sellers. The transaction was funded using cash on hand.

Lease Acquisitions – Over the last three years, we have acquired six leases for approximately $1.5 million from the BOEM in the Federal Offshore Lease Sales. During 2021, we were the high bidder of two leases in Federal Offshore Lease Sale 257. In January 2022, a U.S District Court issued an order that could have invalidated these leases. Effective October 1, 2022, BOEM reinstated and accepted these bids and we were awarded one of these two leases in 2022 and the other in 2023 for approximately $0.1 million and $0.2 million, respectively. We acquired four leases for approximately $1.2 million in 2020.

Divestitures – From time to time, we sell various oil and gas properties for a variety of reasons including, change of focus, perception of value and to reduce debt, among other reasons. In 2022 and 2021, there were no property sales of significance.

Asset retirement obligations – Annually, we review and revise our ARO estimates. Our ARO at December 31, 2022 and 2021 were $466.4 million and $424.5 million, respectively. The increase is primarily due to the acquisition of assets as described above. These increases were partially offset by $76.2 million related to liabilities settled. Our estimate of ARO spending in 2023 is approximately $25.0 to $35.0 million. During 2022 and 2021, we revised our estimates of costs anticipated to be charged by service providers for plugging and abandonment projects and revised estimated to actual spending as invoices were processed and projects 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 Risk Factors – *Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant because our operations are concentrated in the Gulf of Mexico* under Part I, Item 1A and *Financial Statements and Supplementary Data – Note 7 – 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, 2022, we had $147.9 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 the Company and its 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.

Credit Agreement – As of December 31, 2022, we had no borrowings outstanding under the Credit Agreement. On November 7, 2022, the Company entered into the Eleventh Amendment to Sixth Amended and Restated Credit Agreement and Extension Agreement, which extended the maturity date and Lender commitment to January 3, 2024.

9.75% Senior Second Lien Notes due 2023 – As of December 31, 2022, we had $552.5 million principal outstanding of 9.75% Senior Second Lien Notes outstanding. On February 8, 2023, we redeemed all of the 9.75% Senior Second Lien Notes outstanding at a redemption price of 100.000%, plus accrued and unpaid interest to the redemption date. The Company used the net proceeds of $270.8 million from the issuance of the 11.75% Senior Second Lien Notes due 2026 and cash on hand of $296.1 million to fund the redemption and interest. See *Financial Statements and Supplementary Data –Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

11.75% Senior Second Lien Notes due 2026 – On January 27, 2023 we issued and sold $275 million in aggregate principal amount of our 11.75% Senior Second Lien Notes 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. See *Financial Statements and Supplementary Data –Note 20 – Subsequent Events* under Part II, Item 8 in this Form 10-K for additional information.

Debt Covenants – The Term Loan, Credit Agreement, and 9.75% Senior Second Lien 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 9.75% Senior Second Lien Notes. We were in compliance with all applicable covenants of the Term Loan, Credit Agreement and the 9.75% Senior Second Lien Notes indenture as of and for the period ended December 31, 2022. See *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information.

The Subsidiary Borrowers

On May 19, 2021, we formed A-I LLC and A-II LLC, both indirect, wholly-owned subsidiaries of W&T Offshore, Inc., through their parent, Aquasition Energy LLC (collectively, the Aquasition Entities”). Concurrently, A-I LLC and A-II II LLC, entered into a credit agreement providing for the Term Loan in an initial aggregate principal amount equal to $215.0 million. Proceeds of the Term Loan were used by A-I LLC and A-II LLC to fund the acquisition of the Mobile Bay Properties and the Midstream Assets, respectively, from the Company. The Term Loan is non-recourse to the Company and any subsidiaries other than the Aquasition Entities, and is secured by the first lien security interests in the equity of the Aquasition Entities and a first lien mortgage security interest in the Mobile Bay Properties. See *Financial Statements and Supplementary Data – Note 4 – Subsidiary Borrowers* under Part II, Item 8 in this Annual Report for additional information.

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% Senior Second Lien Notes and the liens on the assets sold to the Unrestricted Subsidiaries have been released under the Credit Agreement. The Unrestricted Subsidiaries are not bound by the covenants contained in the Credit Agreement or the Indenture. Under 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 the Company and its 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, 2022 (in thousands):

	Consolidated Balance Sheet	Eliminations of Unrestricted Subsidiaries	Consolidated Balance Sheet of restricted subsidiaries
Assets			
Current assets:			
Cash and cash equivalents	$ 461,357	$ (21,764)	$ 439,593
Restricted cash	4,417	—	4,417
Receivables:			
Oil and natural gas sales	66,146	(37,344)	28,802
Joint interest, net	14,000	5,760	19,760
Total receivables	80,146	(31,584)	48,562
Prepaid expenses and other assets	24,343	(417)	23,926
Total current assets	570,263	(53,765)	516,498
Oil and natural gas properties and other, net	735,215	(280,649)	454,566
Restricted deposits for asset retirement obligations	21,483	—	21,483
Deferred income taxes	57,280	—	57,280
Other assets	47,549	(8,473)	39,076
Total assets	$ 1,431,790	$ (342,887)	$ 1,088,903
Liabilities and Shareholders' Equity (Deficit)			
Current liabilities:			
Accounts payable	$ 68,339	$ (27,387)	$ 40,952
Undistributed oil and natural gas proceeds	41,934	(7,930)	34,004
Asset retirement obligations	25,359	—	25,359
Accrued liabilities	74,041	(45,102)	28,939
Current portion of long-term debt	582,249	(32,119)	550,130
Income tax payable	412	—	412
Total current liabilities	792,334	(112,538)	679,796
Long-term debt			
Principal	114,158	(114,158)	—
Unamortized debt issuance costs	(2,970)	2,970	—
Long-term debt, net	111,188	(111,188)	—
Asset retirement obligations, less current portion	441,071	(61,138)	379,933
Other liabilities	79,491	(47,398)	32,093
Deferred income taxes	72	—	72
Common stock	1	—	1
Shareholders' equity (deficit):			
Additional paid-in capital	576,588	—	576,588
Retained deficit	(544,788)	(10,625)	(555,413)
Treasury stock, at cost	(24,167)	—	(24,167)
Total shareholders' equity (deficit)	7,634	(10,625)	(2,991)
Total liabilities and shareholders' equity (deficit)	$ 1,431,790	$ (342,887)	$ 1,088,903

Below is Consolidating Statement of Operations information reflecting the elimination of the accounts of our Unrestricted Subsidiaries from our Consolidated Statement of Operations for the year ended December 31, 2022 (in thousands):

	Consolidated	Eliminations of Unrestricted Subsidiaries	Consolidated restricted subsidiaries
Revenues:			
Oil	$ 524,274	$ (899)	$ 523,375
NGLs	56,964	(33,367)	23,597
Natural gas	323,831	(223,826)	100,005
Other	15,928	(10,481)	5,447
Total revenues	920,997	(268,573)	652,424
Operating expenses:			
Lease operating expenses	224,414	(52,760)	171,654
Gathering, transportation and production taxes	35,128	(17,692)	17,436
Depreciation, depletion, amortization and accretion	133,630	(2,087)	131,543
General and administrative expenses	73,747	(1,451)	72,296
Total operating expenses	466,919	(73,990)	392,929
Operating income	454,078	(194,583)	259,495
Interest expense, net	69,441	(14,721)	54,720
Derivative loss (gain)	85,533	(141,736)	(56,203)
Other expense, net	14,295	—	14,295
Income before income taxes	284,809	(38,126)	246,683
Income tax expense	53,660	—	53,660
Net income	$ 231,149	$ (38,126)	$ 193,023

The following table presents our produced oil, NGLs and natural gas volumes (net to our interests) from the Mobile Bay Properties for the periods indicated:

	Year Ended December 31, 2022	For the period from May 19, 2021 to December 31, 2021 2022
Production Volumes:		
Oil (MBbls)	17	13
NGLs (MBbls)	941	603
Natural gas (MMcf)	30,052	20,417
Total oil equivalent (MBoe)	5,967	4,019

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

Contractual Obligations

At December 31, 2022, we did not have any financing leases. The following table summarizes our significant contractual obligations by maturity as of December 31, 2022 (in millions):

	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt – principal	$ 700.4	$ 586.2	$ 57.7	$ 48.3	$ 8.2
Long-term debt – interest (1)	73.1	55.8	12.3	4.8	0.2
Operating leases	22.4	1.6	3.5	3.1	14.2
Asset retirement obligations (2)	466.4	25.4	98.1	28.2	314.7
Other liabilities and commitments (3)	109.4	8.5	14.4	13.9	72.6
Total	$ 1,371.7	$ 677.5	$ 186.0	$ 98.3	$ 409.9

(1) Interest payments were calculated through the stated maturity date of the related debt:

(a) interest payments for the Credit Agreement were calculated using the interest rate applied to our outstanding balance as of December 31, 2022 and assumes no change in this interest rate in future periods. In addition, a commitment fee of 3.0% was applied on the available balance as of December 31, 2022 and fees related to letters of credit were estimated at the rate incurred on December 31, 2022;

(b) interest payments on the 9.75% Senior Second Lien Notes were calculated per the terms of the notes; and

(c) interest payments on the Term Loan were calculated at the 7.0% interest rate set forth in the Term Loan.

(2) ARO in the above table is presented on a discounted basis, consistent with the amounts reported on the Consolidated Balance Sheet as of December 31, 2022 and are estimates of future payments. Actual payments and the timing of the payments may be significantly different than our estimates. All other amounts in the above table are presented on an undiscounted basis.

(3) 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, 2022, we had approximately $438.0 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 includes estimates of minimum quantities obligations for certain pipeline contracts which were assumed in conjunction with the purchase of an interest in the Heidelberg field. The above table excludes 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 16 – Commitments* under Part II, Item 8 in this 10-K for additional information.

Seasonality and Inflation

See Risk Factors – *Crude oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond our control. Depressed oil, natural gas or NGL prices adversely affects 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* under Part I, Item 1A in this Form 10-K and Item 1 *Business – Seasonality and Inflation*, under Part I, Item 1 in this form 10-K for additional information.

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.

Revenue Recognition. Revenues are recorded from the sale of oil, natural gas and NGLs 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. This typically occurs when production has been delivered to a pipeline.

Revenues are recorded based on the actual sales volumes sold to purchasers. An imbalance receivable or payable is recorded only to the extent the imbalance is in excess of its share of remaining proved developed reserves in an underlying property. Our imbalances are recorded gross on our Consolidated Balance Sheets.

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, the Company's 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 Company's Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. The Company performs this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, the Company utilizes SEC pricing when performing the ceiling test. The Company also holds 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 2022, 2021 or 2020.

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 crude oil, natural gas and natural gas liquids 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 crude oil 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.

Asset retirement obligations. The Company has obligations associated with the retirement of its 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. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, 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. 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 the Company incurs an amount different from the amount accrued for decommissioning obligations, the Company recognizes the difference as an adjustment to proved 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 its 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.

The Company accounts for uncertainty in income taxes recognized in the 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, the Company recognizes 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

We are exposed to market risks arising from fluctuating prices of crude oil, NGLs, natural gas and interest rates as discussed below. We have utilized derivative contracts to reduce the risk of fluctuations in commodity prices and expect to use these instruments in the future. While derivative contracts are intended to reduce the effects of volatile oil prices, they may also limit income from favorable price movements. For additional details about our derivative contracts, refer to *Financial Statements and Supplementary Data – Note 10 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K.

Commodity price risk. Oil, NGL, and natural gas prices can fluctuate significantly and have a direct impact on our revenues, earnings and cash flow. For example, assuming a 10% decline in our average realized oil, NGLs and natural gas sales prices in 2022 and assuming no other items had changed, our revenue would have decreased by approximately $106 million in 2022. If costs and expenses of operating our properties had increased by 10% in 2022, our income before income tax would have decreased by approximately $47 million in 2022. These amounts would be representative of the effect on operating cash flows under these price and cost change assumptions.

We have attempted to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of swaps, costless collars, purchased calls, and purchased puts. These contracts will impact our earnings as the fair value of these derivatives changes. Our derivatives will not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we will be subject to commodity price risks on our remaining forecasted production. During the year ended December 31, 2022, our average realized oil price after the effect of derivatives increased 46.4% to $81.24 per Bbl from $55.50 per Bbl during the year-ended December 31, 2021. Our average natural gas price realizations after the effect of derivatives increased 159.2% during the year ended December 31, 2022 to $7.88 per Mcf from $3.04 per Mcf during the year-ended December 31, 2021.

Interest rate risk. As of December 31, 2022, we had no debt outstanding on our Credit Agreement. The Credit Agreement has a variable interest rate which is primarily impacted by the rates for the Secured Overnight Financing Rate ("SOFR") and the current margin is 6.0% per annum. We did not have any derivative contracts related to interest rates as of December 31, 2022.

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, 2022 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, 2022 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, 2022, 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, 2022, 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, 2022 and 2021, the related consolidated statements of operations, changes in shareholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and our report dated March 9, 2023 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 8, 2023

Report of Independent Registered Public Accounting Firm

The Shareholders and 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, 2022 and 2021, the related consolidated statements of operations, changes in shareholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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 9, 2023 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, 2022, the net book value of the Company's oil and natural gas properties was $735 million, and depreciation, depletion and amortization ("DD&A") expense was $107 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 gas exploration and production activities. Under this method, depreciation and depletion are recorded on a units-of-production basis based on estimated proved reserves. Capitalized acquisition, exploration, development, and abandonment costs are amortized on the basis of total proved 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. Significant 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 oil and natural gas price assumptions, as well as 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, 2022. 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 management's determination 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 proved oil and gas reserves as an input to the DD&A expense calculation. This included management's controls over the completeness and accuracy of the financial data used 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 gas reserve balances from the Company's reserve report.

Accounting for Asset Retirement Obligation

Description of the Matter	At December 31, 2022, the asset retirement obligation (ARO) balance totaled $466 million. As further described in Notes 1 and 7 to the consolidated financial statements, the Company records a liability for ARO in the period in which it is incurred. 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 highly judgmental because of the significant estimation required by management in determining the obligation. In particular, the estimate was sensitive to significant subjective assumptions such as retirement cost estimates and the estimated timing of settlements, which are both affected by expectations about future market and economic conditions

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. To test the ARO, 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.

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

/s/ Ernst & Young LLP

Houston, Texas
March 8, 2023

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 461,357	$ 245,799
Restricted cash	4,417	4,417
Receivables:		
Oil and natural gas sales	66,146	54,919
Joint interest, net	14,000	9,745
Total receivables	80,146	64,664
Prepaid expenses and other assets (Note 1)	24,343	43,379
Total current assets	570,263	358,259
Oil and natural gas properties and other, net (Note 1)	735,215	665,252
Restricted deposits for asset retirement obligations	21,483	16,019
Deferred income taxes	57,280	102,505
Other assets (Note 1)	47,549	51,172
Total assets	$ 1,431,790	$ 1,193,207
Liabilities and Shareholders' Equity (Deficit)		
Current liabilities:		
Accounts payable	$ 65,158	$ 67,409
Undistributed oil and natural gas proceeds	41,934	36,243
Advances from joint interest partners	3,181	15,072
Asset retirement obligations	25,359	56,419
Accrued liabilities (Note 1)	74,041	106,140
Current portion of long-term debt, net	582,249	42,960
Income tax payable	412	133
Total current liabilities	792,334	324,376
Long-term debt (Note 2)		
Principal	114,158	700,359
Unamortized debt issuance costs	(2,970)	(12,421)
Long-term debt, net (Note 2)	111,188	687,938
Asset retirement obligations, less current portion	441,071	368,076
Other liabilities (Note 1)	59,134	55,389
Deferred income taxes	72	113
Commitments and contingencies (Note 12)	20,357	4,495
Shareholders' equity (deficit):		
Preferred stock, $0.00001 par value; 20,000 shares authorized; none issued at December 31, 2022 and December 31, 2021	—	—
Common stock, $0.00001 par value; 200,000 shares authorized; 149,002 issued and 146,133 outstanding at December 31, 2022; 145,732 issued and 142,863 outstanding at December 31, 2021	1	1
Additional paid-in capital	576,588	552,923
Retained deficit	(544,788)	(775,937)
Treasury stock, at cost; 2,869 shares at December 31, 2022 and December 31, 2021	(24,167)	(24,167)
Total shareholders' equity (deficit)	7,634	(247,180)
Total liabilities and shareholders' equity (deficit)	$ 1,431,790	$ 1,193,207

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except per share data)

	Year Ended December 31,		
	2022	2021	2020
Revenues:			
Oil	$ 524,274	$ 329,557	$ 216,419
NGLs	56,964	44,343	19,101
Natural gas	323,831	173,749	99,300
Other	15,928	10,361	11,814
Total revenues	920,997	558,010	346,634
Operating expenses:			
Lease operating expenses	224,414	174,582	162,857
Gathering, transportation and production taxes	35,128	27,919	20,947
Depreciation, depletion, and amortization	107,122	90,522	97,763
Asset retirement obligations accretion	26,508	22,925	22,521
General and administrative expenses	73,747	52,400	41,745
Total operating expenses	466,919	368,348	345,833
Operating income	454,078	189,662	801
Interest expense, net	69,441	70,049	61,463
Derivative loss (gain)	85,533	175,313	(23,808)
Gain on debt transactions	—	—	(47,469)
Other expense (income), net	14,295	(6,165)	2,978
Income (loss) before income taxes	284,809	(49,535)	7,637
Income tax expense (benefit)	53,660	(8,057)	(30,153)
Net income (loss)	$ 231,149	$ (41,478)	$ 37,790
Net income (loss) per common share:			
Basic	$ 1.61	$ (0.29)	$ 0.26
Diluted	1.59	(0.29)	0.26
Weighted average common shares outstanding:			
Basic	143,143	142,271	141,622
Diluted	145,090	142,271	143,277

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (DEFICIT)
(In thousands)

	Common Stock Outstanding		Additional Paid-In	Retained	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	Deficit	Shares	Value	Equity (Deficit)
Balances at December 31, 2019	141,669	1	547,050	(772,249)	2,869	(24,167)	(249,365)
Share-based compensation	—	—	3,959	—	—	—	3,959
Stock issued	636	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(670)	—	—	—	(670)
Net income	—	—	—	37,790	—	—	37,790
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
Stock issued	558	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(780)	—	—	—	(780)
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
Stock issued	299	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(715)	—	—	—	(715)
At-the-market equity offering	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

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2022	2021	2020
Operating activities:			
Net income (loss)	$ 231,149	$ (41,478)	$ 37,790
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	133,630	113,447	120,284
Amortization of debt items and other items	7,551	6,555	6,834
Share-based compensation	7,922	3,364	3,959
Derivative loss (gain)	85,533	175,313	(23,808)
Derivative cash (payments) receipts, net	(41,880)	(81,298)	45,196
Derivative cash premium payments	(46,111)	(40,484)	—
Gain on debt transactions	—	—	(47,469)
Deferred income taxes	45,184	(8,189)	(30,287)
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(11,227)	(16,089)	18,537
Joint interest receivables	(4,255)	1,095	8,561
Prepaid expenses and other assets	31,906	(5,103)	9,563
Income tax	279	(20)	2,014
Asset retirement obligation settlements	(76,225)	(27,309)	(3,339)
Cash advances from JV partners	(11,892)	7,765	2,028
Accounts payable, accrued liabilities and other	(12,034)	46,099	(41,354)
Net cash provided by operating activities	339,530	133,668	108,509
Investing activities:			
Investment in oil and natural gas properties and equipment	(41,632)	(32,062)	(17,632)
Changes in operating assets and liabilities associated with investing activities	(1,894)	5,277	(26,535)
Acquisition of property interests	(51,474)	(661)	(2,919)
Purchases of furniture, fixtures and other	(80)	2	(530)
Net cash used in investing activities	(95,080)	(27,444)	(47,616)
Financing activities:			
Borrowings on credit facility	—	—	25,000
Repayments on credit facility	—	(80,000)	(50,000)
Purchase of 9.75% Senior Second Lien Notes	—	—	(23,930)
Proceeds from Term Loan	—	215,000	—
Repayments on Term Loan	(42,959)	(24,142)	—
Debt issuance costs	(1,675)	(9,810)	—
Proceeds from at-the-market equity offering	16,998	—	—
Commission & fees related to at-the-market sales	(540)	—	—
Other	(716)	(782)	(670)
Net cash (used in) provided by financing activities	(28,892)	100,266	(49,600)
Increase in cash and cash equivalents	215,558	206,490	11,293
Cash and cash equivalents and restricted cash, beginning of period	250,216	43,726	32,433
Cash and cash equivalents and restricted cash, end of period	$ 465,774	$ 250,216	$ 43,726

See accompanying notes.

NOTE 1 — SIGNIFICANT ACCOUNTING POLICIES

Operations

W&T Offshore, Inc. (with subsidiaries referred to herein as "W&T" or 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").

Basis of Presentation

The Consolidated Financial Statements include the accounts of W&T Offshore, Inc., its majority-owned subsidiary and the proportionately consolidated interests in oil and gas joint ventures. All significant intercompany transactions have been eliminated.

The Consolidated Financial Statements have been prepared in accordance with U.S. GAAP and the appropriate rules and regulations of the SEC.

Reclassification – For presentation purposes, as of December 31, 2020, *Derivative loss (gain)* has been moved out of "Operating income (loss)" on the Consolidated Statement of Operations in order to conform to current period presentation. Additionally, as of December 31, 2020, *Gathering and transportation* and *Production taxes* have been combined into one line item within "Operating income" on the Consolidated Statement of Operations in order to conform to the current period presentation. Such reclassifications had no effect on the Company's results of operations, financial position or cash flows.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

Cash Equivalents

W&T 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

As of December 31, 2021, the Company cash collateralized each of the outstanding letters of credit in the aggregate amount of approximately $4.4 million. See *Note 2 –Debt* for additional information.

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 crude 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.

W&T 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, 2022 and 2021, $3.5 million, is included as a current liability in *Undistributed oil and natural gas proceeds* on 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.

The following table identifies customers whose total represented 10% or more of the Company's receipts from sales of crude oil, NGLs and natural gas:

	Year Ended December 31,		
	2022	2021	2020
Customer			
BP Products North America	31 %	34 %	39 %
Chevron - Texaco	13 %	14 %	**
Mercuria Energy America Inc.	**	**	10 %
Williams Field Services	**	11 %	13 %

** Less than 10%

The loss of any of the customers above would not 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 Receivables 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):

	2022	2021	2020
Allowance for credit losses, beginning of period	$ 10,046	$ 9,123	$ 9,898
Additional provisions for the year	3,085	2,192	417
Uncollectible accounts written off or collected	(1,069)	(1,269)	(1,192)
Allowance for credit losses, end of period	$ 12,062	$ 10,046	$ 9,123

Prepaid expenses and other assets

Amounts recorded in *Prepaid expenses and other assets* on the Consolidated Balance Sheets are expected to be realized within one year. The following table provides the primary components (in thousands):

	December 31, 2022	December 31, 2021
Derivatives[1] (Note 10)	$ 4,954	$ 21,086
Unamortized insurance/bond premiums	6,046	5,400
Prepaid deposits related to royalties	9,139	8,441
Prepayment to vendors	1,767	4,522
Prepayments to joint interest partners	1,717	2,808
Debt issue costs	687	1,065
Other	33	57
Prepaid expenses and other assets	$ 24,343	$ 43,379

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

Oil and Natural Gas Properties and Other, Net

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, 2022 and 2021, there were no unproved properties included in the *Oil and natural gas properties and other, net*. 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 five 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.

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

	December 31,	
	2022	2021
Oil and natural gas properties and equipment	$ 8,813,404	$ 8,636,408
Furniture, fixtures and other	20,915	20,844
Total property and equipment	8,834,319	8,657,252
Less: Accumulated depreciation, depletion, amortization and impairment	(8,099,104)	(7,992,000)
Oil and natural gas properties and other, net	$ 735,215	$ 665,252

Ceiling Test Write-Down

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 2022, 2021 or 2020. If average crude oil and natural gas prices decrease below average pricing during 2022, the Company could incur ceiling test write-downs in future periods.

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 19 – 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. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site cleanup. The Company records a separate liability for the present value of ARO based on the estimated timing and amount to replace, remove or retire the associated assets, with an offsetting increase to the related oil and natural gas properties on the balance sheet.

In estimating the liability associated with its asset retirement obligations, 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. See *Note 7 – Asset Retirement* Obligations for additional information.

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 18 —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 loss (gain)* on the Consolidated Statement of Operations. See *Note 10 – 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 13 – Income Taxes* for additional information.

Other Assets (long-term)

The major categories recorded in *Other assets* are presented in the following table (in thousands):

	December 31,	
	2022	2021
Right-of-Use assets	$ 10,364	$ 10,602
Investment in White Cap, LLC	2,453	2,533
Proportional consolidation of Monza (Note 5)	9,321	2,511
Derivatives[1] (Note 10)	23,236	34,435
Other	2,175	1,091
Total other assets (long-term)	$ 47,549	$ 51,172

(1) Includes open contracts.

Accrued Liabilities

The major categories recorded in *Accrued liabilities* are presented in the following table (in thousands):

	December 31,	
	2022	2021
Accrued interest	$ 8,967	$ 10,154
Accrued salaries/payroll taxes/benefits	15,097	9,617
Litigation accruals	396	646
Lease liability	1,628	1,115
Derivatives[1] (Note 10)	46,595	81,456
Other	1,358	3,152
Total accrued liabilities	$ 74,041	$ 106,140

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

Paycheck Protection Program ("PPP")

On April 15, 2020, the Company received $8.4 million under the U.S. Small Business Administration ("SBA") PPP. The Company's application to the SBA requesting that the PPP funds received be applied to specific covered and non-covered payroll costs was accepted and approved for full forgiveness on June 11, 2021. As there is no definitive guidance under U.S. GAAP, the Company has applied the guidance under IAS 20 and accounted for the PPP as a government grant. Under IAS 20, a government grant is recognized when there is reasonable assurance that the Company has complied with the provisions of the grant. Accordingly, the funds received were recorded as a reduction to *General and administrative expenses* on the Consolidated Statement of Operations during the year-ended December 31, 2020. No such credit was recognized during the years ended December 31, 2022 or 2021.

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 9.75% Senior Second Lien Notes and the Term Loan 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. See *Note 2 –Debt* for additional information.

Gain on Debt Transactions

During 2020, the Company acquired $72.5 million in principal of the outstanding 9.75% Senior Second Lien Notes for $23.9 million and recorded a non-cash gain on purchase of debt of $47.5 million.

Other Liabilities (long-term)

The major categories recorded in *Other liabilities* are presented in the following table (in thousands):

	December 31, 2022	December 31, 2021
Dispute related to royalty deductions	$ 4,937	$ 5,177
Derivatives (Note 10)	43,061	37,989
Lease liability	10,527	11,227
Other	609	996
Total other liabilities (long-term)	$ 59,134	$ 55,389

At-the-Market Equity Offering

On March 18, 2022, the Company filed a prospectus supplement related to the issuance and sale of up to $100,000,000 of shares of common stock under the Company's ATM Program. The designated sales agent is entitled to a placement fee of up to 3.0% of the gross sales price per share sold. During the year ended December 31, 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.

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 11 – Share-Based Awards and Cash-Based Awards* for additional information.

Employee Retention Credit

Under the Consolidated Appropriations Act, 2021 passed by the United States Congress and signed by the President on December 27, 2020, provisions of the Coronavirus Aid, Relief and Economic Security Act were extended and modified making the Company eligible for a refundable employee retention credit subject to meeting certain criteria. The Company recognized a $2.1 million employee retention credit during the year ended December 31, 2021. The funds received were recorded as a reduction to General and administrative on the Consolidated Statement of Operations during the year ended December 31, 2021. No such credit was recognized during the years ended December 31, 2022 or 2020.

Other Expense (Income), Net

For the year ended December 31, 2022, *Other expense (income), net* primarily consists of other expense related to the additional contingent decommissioning obligations recognized during the year ended December 31, 2021.

For the year ended December 31, 2021, the amount primarily consists 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 recognized during the year ended December 31, 2021.

For the year ended December 31, 2020, the amount primarily consists of expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program.

See *Note 9 – Restricted Deposits for ARO and Note 18 —Contingencies* for additional information.

Earnings Per Share

Unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per share under the two-class method when the effect is dilutive. See *Note 14 – Earnings Per Share* for additional information.

NOTE 2 — DEBT

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

	December 31,	
	2022	2021
Term Loan:		
Principal	$ 147,899	$ 190,859
Unamortized debt issuance costs	(4,592)	(7,545)
Total Term Loan	143,307	183,314
Credit Agreement borrowings:	—	—
9.75% Senior Second Lien Notes:		
Principal	552,460	552,460
Unamortized debt issuance costs	(2,330)	(4,876)
Total 9.75% Senior Second Lien Notes	550,130	547,584
Less current portion, net	(582,249)	(42,960)
Total long-term debt, net	$ 111,188	$ 687,938

Aggregate annual maturities of principal amounts recorded as of December 31, 2022 are as follows (in millions):

2023	$ 586.2
2024	30.1
2025	27.6
2026	25.4
2027	22.9
Thereafter	8.2
Total	$ 700.4

Current portion of Long-Term Debt

As of December 31, 2022, the current portion of long-term debt of $582.2 million represented net principal payments due within one year on the Term Loan and 9.75% Senior Second Lien Notes. See *Note 20 – Subsequent Events* for additional information.

Term Loan (Subsidiary Credit Agreement)

On May 19, 2021, A-I LLC and A-II LLC, subsidiaries of W&T Offshore, Inc., entered into a credit agreement (the “Subsidiary Credit Agreement”) providing for a term loan (the “Term Loan”) in an aggregate principal amount equal to $215.0 million. The Term Loan requires quarterly amortization payments which commenced on September 30, 2021. The Term Loan bears interest at a fixed rate of 7.0% per annum and will mature on May 19, 2028.

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 crude oil treating and sweetening facility, an onshore gathering pipeline, and associated assets (such assets, the “Midstream Assets”). During 2021, a portion of the proceeds to the Company was used to repay the $48.0 million outstanding balance on its reserve-based lending facility under the Credit Agreement.

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, 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 4 – Subsidiary Borrowers* for additional information.

During the years ended December 31, 2022 and 2021, the Company repaid $43.0 million and $24.1 million of principal outstanding, respectively. As of December 31, 2022 and 2021, the Company had $147.9 million and $190.9 million in principal amount of the Term Loan, respectively.

Credit Agreement

On November 2, 2021, the Company entered into the Ninth Amendment to the Sixth Amended and Restated Credit Agreement (the “Ninth Amendment”), 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 W&T’s Chairman and Chief Executive Officer, Tracy W. Krohn, as sole lender under the Calculus Lending 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 March 8, 2022, the Company entered into the Tenth Amendment to the Sixth Amended and Restated Credit Agreement (the “Tenth Amendment”), which extended the maturity date and Calculus’ commitment to January 3, 2023. On November 7, 2022, the Company entered into the Eleventh Amendment to the Credit Agreement (the “Eleventh Amendment”), 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.

A committee of the independent members of the Board of Directors reviewed and approved these amendments given the CEO’s affiliation with Calculus. See *Note 17 – Related Parties* for additional information.

As a result of the Ninth Amendment, Tenth Amendment and Eleventh Amendment and related assignments and agreements, the primary terms and covenants associated with the Credit Agreement as of December 31, 2022, are as follows:

- The borrowing base is $50.0 million.
- The Calculus Lending facility commitment will expire and final maturity of any and all outstanding loans is January 3, 2024. Outstanding borrowings will accrue interest at SOFR plus 6.0% per annum. The commitment fee for the unused portion of available borrowing amounts will be 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 on the last day of the fiscal quarter ended March 31, 2022 and on the last day of each fiscal quarter thereafter;
- 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 commencing with the fiscal quarter ended March 31, 2022 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 commencing with the fiscal quarter ended March 31, 2022, the Company and its restricted subsidiaries on a consolidated basis must pass a "Stress Test" consisting of an analysis conducted by the lender in good faith and in consultation with the Company based upon the latest engineering report furnished to lender, which analysis is designed to determine whether the future net revenues expected to accrue to the Company's and its guarantor subsidiaries' interest (and the interest of certain joint ventures) in the oil and gas properties included in the properties used to determine the latest borrowing base during half of the remaining expected economic lives of such properties are sufficient to satisfy the aggregate first lien indebtedness of the Company and its restricted subsidiaries in accordance with the terms of such indebtedness assuming the Calculus Lending facility is 100% funded or fully utilized.
- 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. The borrowing base is calculated by the lender based on their evaluation of proved reserves and their own internal criteria. Any redetermination by the lender to change the borrowing base will result in a similar change in the availability under the Credit Agreement. The Credit Agreement is secured by a first priority lien on substantially all of the Company's oil and natural gas properties and personal property, excluding those assets of the Subsidiary Borrowers, which liens were released (as described in *Note 4 – Subsidiary Borrowers*).

As of December 31, 2022 and 2021, there were no borrowings outstanding or incurred under the Credit Agreement. As of December 31, 2022 and 2021, the Company had $4.4 million, outstanding in letters of credit which are cash collateralized.

9.75% Senior Second Lien Notes Due 2023

On October 18, 2018, the Company issued $625.0 million of 9.75% Senior Second Lien Notes due 2023 (the "9.75% Senior Second Lien Notes"), which were issued at par with an interest rate of 9.75% per annum that matures on November 1, 2023, and are governed under the terms of the Indenture of the 9.75% Senior Second Lien Notes entered into by and among the Company, the Guarantors, and Wilmington Trust, National Association, as trustee. The estimated annual effective interest rate on the 9.75% Senior Second Lien Notes was 10.3%, which includes debt issuance costs. Interest on the 9.75% Senior Second Lien Notes is payable in arrears on May 1 and November 1 of each year.

During the year ended December 31, 2020, the Company acquired $72.5 million in principal of the outstanding 9.75% Senior Second Lien Notes for $23.9 million and recorded a non-cash gain on purchase of debt of $47.5 million, which included a reduction of $1.1 million related to the write-off of unamortized debt issuance costs.

Subsequent to December 31, 2022, the Company redeemed all of the outstanding 9.75% Senior Second Lien Notes using cash on hand and the net proceeds from the offering of the 11.75% Senior Second Lien Notes. See *Note 20 – Subsequent Events* for additional information.

Covenants

As of December 31, 2022 and for all presented measurement periods, the Company was in compliance with all applicable covenants of the Credit Agreement and 9.75% Senior Second Lien Notes.

NOTE 3 — FAIR VALUE MEASUREMENTS

Under GAAP, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. 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 10 – Derivative Financial Instruments* for additional information.

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

	December 31, 2022	December 31, 2021
Assets:		
Derivative instruments - current	$ 4,954	$ 21,086
Derivative instruments - long-term	23,236	34,435
Liabilities:		
Derivative instruments - current	46,595	81,456
Derivative instruments - long-term	43,061	37,989

Debt Instruments

The fair value of the Term Loan was measured using a discounted cash flows model and current market rates. The fair value of the 9.75% Senior Second Lien Notes was 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, 2022		December 31, 2021	
	Net Value	Fair Value	Net Value	Fair Value
Liabilities:				
Term Loan	$ 143,307	$ 139,056	$ 183,314	$ 190,579
9.75% Senior Second Lien Notes	550,130	544,902	547,584	527,715
Total	$ 693,437	$ 683,958	$ 730,898	$ 718,294

NOTE 4 — SUBSIDIARY BORROWERS

On May 19, 2021, the Subsidiary Borrowers entered into the Subsidiary Credit Agreement providing for the Term Loan in an aggregate principal amount equal to $215.0 million. Proceeds of the Term Loan were used by the Borrowers 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 10 – 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 i) the Mobile Bay Properties and ii) the Midstream Assets and (b) certain corporate, general and administrative services for A-I LLC and A-II LLC (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 the year ended December 31, 2022, the Subsidiary Borrowers paid cash distributions to W&T of $30.2 million.

Consolidation and Carrying Amounts

The following table presents the amounts recorded by W&T on the Consolidated Balance Sheets related to the consolidation of the Subsidiary Borrowers and the subsidiary that owns the equity of the Subsidiary Borrowers (in thousands):

	December 31,	
	2022	2021
Assets:		
Cash and cash equivalents	$ 21,764	$ 38,937
Receivables:		
Oil and natural gas sales	37,344	34,420
Joint interest, net	(5,760)	(10,856)
Prepaid expenses and other assets	417	356
Oil and natural gas properties and other, net	280,649	272,747
Other assets	8,473	(19,903)
Liabilities:		
Accounts payable	27,387	29,678
Undistributed oil and natural gas proceeds	7,930	3,144
Accrued liabilities	45,102	29,937
Current portion of long-term debt	32,119	42,960
Long-term debt, net	111,188	140,353
Asset retirement obligations	61,138	54,515
Other liabilities	47,398	42,615

The following table presents the amounts recorded by W&T in the Consolidated Statement of Operations related to the consolidation of the operations of the Subsidiary Borrowers and the subsidiary that owns the equity of the Subsidiary Borrowers (in thousands):

	Year Ended December 31, 2022	The period from May 19, 2021 to December 31, 2021
Total revenues	$ 268,573	$ 119,550
Total operating expenses	73,990	32,735
Interest expense, net	14,721	9,782
Derivative loss	141,736	104,533

NOTE 5 — JOINT VENTURE DRILLING PROGRAM

In March 2018, W&T and two other initial members formed and initially 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. Subsequent to the initial closing, additional investors joined as members of Monza during 2018 and total commitments by all members, including W&T's commitment outside of Monza, were $361.4 million. W&T 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.

The members of Monza are made up of third-party investors, W&T and an entity owned and controlled by Tracy W. Krohn, the Company's Chairman and Chief Executive Officer. The entity affiliated with the Company's CEO invested as a minority investor on the same terms and conditions as the third-party investors, and its investment is limited to 4.5% of total invested capital within Monza. The entity affiliated with Mr. Krohn has 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.

Through December 31, 2022, ten wells have been completed of which six were producing as of December 31, 2022. W&T is the operator for eight of the ten wells completed through December 31, 2022.

Since inception through December 31, 2022, members of Monza made partner capital contributions, including W&T's contributions of working interest in the drilling projects, to Monza totaling $302.4 million and received cash distributions totaling $166.0 million. Since inception through December 31, 2022, W&T 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 $35.7 million.

Consolidation and Carrying Amounts

W&T's interest in Monza is considered to be a variable interest that is proportionally consolidated. Through December 31, 2022, there have been no events or changes that would cause a redetermination of the variable interest status. W&T does not fully consolidate Monza because the Company is not considered the primary beneficiary of Monza.

The following table presents the amounts recorded by W&T on the Consolidated Balance Sheets related to the consolidation of the proportional interest in Monza's operations (in thousands):

	December 31,	
	2022	2021
Working capital	$ 2,515	$ 4,648
Oil and natural gas properties and other, net	37,260	45,510
Asset retirement obligations	467	301
Other assets	11,571	2,511

As required, W&T may call on Monza to provide cash to fund its portion of certain Joint Venture Drilling Program projects in advance of capital expenditure spending, and the unused balances as of December 31, 2022 and December 31, 2021 were $2.9 million and $14.8 million, respectively, which are included in the Consolidated Balance Sheets in *Advances from joint interest partners.*

The following table presents the amounts recorded by W&T in the Consolidated Statement of Operations related to the consolidation of the proportional interest in Monza's operations (in thousands):

	Year Ended December 31,	
	2022	2021
Total revenues	$ 28,803	$ 12,716
Total operating expenses	13,523	10,044
Derivative loss	—	2,096
Interest income	42	—

NOTE 6 — ACQUISITIONS

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, the transactions were accounted for as asset acquisitions in accordance with ASC 805. 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 significant 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 on February 1, 2022, and April 1, 2022, are presented in the following tables, respectively (in thousands):

	February 1, 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 1, 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 7 — 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,	
	2022	2021
Asset retirement obligations, beginning of period	$ 424,495	$ 392,704
Liabilities settled	(76,225)	(27,309)
Accretion expense	26,508	22,925
Liabilities acquired	33,202	454
Liabilities incurred	138	—
Revisions of estimated liabilities	58,312	35,721
Asset retirement obligations, end of period	466,430	424,495
Less: Current portion	(25,359)	(56,419)
Long-term	$ 441,071	$ 368,076

NOTE 8 — LEASES

The Company has operating leases consisting of office leases, 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, inflation rates 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 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 property and equipment, lease operating expense or general and administrative expense, as applicable. The components of lease costs were as follows (in thousands):

	December 31, 2022	December 31, 2021	December 31, 2020
Operating lease costs, excluding short-term leases	$ 1,579	$ 1,743	$ 3,060
Short-term lease cost [1]	2,957	5,926	1,633
Variable lease cost [2]	647	—	—
Total lease cost	$ 5,183	$ 7,669	$ 4,693

(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 and other, net*, on 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 right-of-use asset and liability, adjusted for initial direct costs and incentives are as follows (in thousands):

	December 31, 2022	December 31, 2021
ROU assets	$ 10,364	$ 10,602
Lease liability:		
Accrued liabilities	$ 1,628	$ 1,115
Other liabilities	10,527	11,227
Total lease liability	$ 12,155	$ 12,342

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

	December 31, 2022	December 31, 2021	December 31, 2020
Weighted average remaining lease term:	13.1 years	14.1 years	14.8 years
Weighted average discount rate:	10.1 %	10.1 %	10.2 %

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

	December 31, 2022	December 31, 2021	December 31, 2020
Operating cash outflow from operating leases	$ 1,224	$ 425	$ 1,825
Right-of-use assets obtained in exchange for new operating lease liabilities	$ —	$ —	$ 5,142

Undiscounted future minimum payments as of December 31, 2022 are as follows (in thousands):

2023	$ 1,628
2024	2,026
2025	1,514
2026	1,545
2027	1,576
Thereafter	14,242
Total lease payments	22,531
Present value adjustment	(10,376)
Total	$ 12,155

NOTE 9 — RESTRICTED DEPOSITS FOR ARO

Restricted deposits as of December 31, 2022 and 2021 consisted of funds escrowed for collateral related to the future plugging and abandonment obligations of certain oil and natural gas properties as follows:

	December 31,	
	2022	2021
Main Pass 283/Viosca Knoll 734 [(1)]	$ 13,684	$ 13,663
Eugene Island 205/89 [(2)]	—	1,880
South Marsh Island 73 [(3)]	7,753	—
Other	47	477

(1) In connection with a prior period acquisition of the Main Pass 283 and Viosca Knoll 734 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 a prior period acquisition of the Eugene Island 205 and 89 fields, the Company received funds from the previous owner to cover future asset retirement obligations for those fields. As of December 31, 2022, the Company has performed the related plugging and abandonment work at both fields.

(3) During the first and second quarter of 2022, the Company acquired the South Marsh Island 73 field. As part of the transaction, the Company received a total of $7.8 million 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 6 - Acquisitions* for additional information.

Black Elk Escrow – On December 29, 2021, the United States Bankruptcy Court for the Southern District of Texas sent the Company notice that it is able to retain the remaining funds related to Black Elk liquidation in 2020 and that those funds were no longer subject to any restrictions, effectively releasing the cash from escrow. Accordingly, the Company removed the remaining liability of $11.1 million and transferred the related cash previously retained in escrow to cash. The Company recorded the $11.1 million in *Other (income) expense* during the year ended December 31, 2021.

NOTE 10 — DERIVATIVE FINANCIAL INSTRUMENTS

W&T'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.

W&T 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 loss (gain)* 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 crude oil contracts are based on WTI crude oil prices and the natural gas contracts are based off the Henry Hub prices, both of which are quoted off NYMEX.

The following table reflects the contracted volumes and weighted average prices under the terms of the Company's open derivative contracts as of December 31, 2022:

Period	Instrument Type	Average Daily Volumes	Total Volumes	Weighted Strike Price	Weighted Put Price	Weighted Call Price
Natural Gas - Henry Hub (NYMEX)		*(MMbtu)*	*(MMbtu)*	*($/MMbtu)*	*($/MMbtu)*	*($/MMbtu)*
Jan 2023 - Dec 2023	calls	70,000	25,550,000	$ —	$ —	$ 7.50
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 2023 - Dec 2023(1)	swaps	72,329	26,400,000	$ 2.48	$ —	$ —
Jan 2024 - Dec 2024(1)	swaps	65,574	24,000,000	$ 2.46	$ —	$ —
Jan 2025 - Mar 2025(1)	swaps	63,333	5,700,000	$ 2.72	$ —	$ —
Apr 2025 - Dec 2025(1)	puts	62,182	17,100,000	$ —	$ 2.27	$ —
Jan 2026 - Dec 2026(1)	puts	55,890	20,400,000	$ —	$ 2.35	$ —
Jan 2027 - Dec 2027(1)	puts	52,603	19,200,000	$ —	$ 2.37	$ —
Jan 2028 - Apr 2028(1)	puts	49,587	6,000,000	$ —	$ 2.50	$ —

(1) These contracts were entered into by the Company's wholly owned subsidiary, A-I LLC (see *Note 4 – Subsidiary Borrowers).*

Financial Statement Presentation

The following fair value of derivative financial instruments amounts were recorded in the Consolidated Balance Sheets (in thousands):

	December 31, 2022	December 31, 2021
Prepaid expenses and other current assets	$ 4,954	$ 21,086
Other assets (long-term)	23,236	34,435
Accrued liabilities	46,595	81,456
Other liabilities (long-term)	43,061	37,989

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

	Year Ended December 31,		
	2022	2021	2020
Realized loss (gain)(1)	$ 125,089	$ 95,187	$ (33,415)
Unrealized (gain) loss	(39,556)	80,126	9,607
Derivative loss (gain)	85,533	175,313	(23,808)

(1) The year ended December 31, 2022 includes the effects of the $138.0 million realized gain related to the monetization of certain natural gas call contracts through restructuring of strike prices which occurred in June 2022.

Cash payments on commodity derivative contract settlements, net, are included within *Net cash provided by operating activities* on the Consolidated Statements of Cash Flows and were as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Derivative loss (gain)	$ 85,533	$ 175,313	$ (23,808)
Derivative cash (payments) receipts, net(1)	(41,880)	(81,298)	45,196
Derivative cash premium payments	(46,111)	(40,484)	—

(1) The year ended December 31, 2022 includes $105.3 million of net cash receipts related to the monetization of certain natural gas call contracts through restructuring of strike prices.

NOTE 11 — SHARE-BASED AWARDS AND CASH BASED AWARDS

Incentive Compensation Plan

The W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (as amended, from time to time, the “Plan”) was approved by the Company’s shareholders. The Plan covers the Company’s eligible employees and consultants and includes both cash and share-based compensation awards. The 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”).

Pursuant to the terms of the 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 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, 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 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.

Restricted Stock Units

During 2022 and 2021, the Company granted RSUs under the Plan to certain of its employees. There were no RSUs granted in 2020. RSUs are a long-term compensation component, granted to certain employees.

As of December 31, 2022, there were 9,595,681 shares of common stock available for issuance in satisfaction of awards under the Plan. The shares available for issuance are reduced on a one-for-one basis when RSUs are settled in shares of common stock, net of withholding tax through the withholding of shares. The Company has the option following vesting to settle RSUs in stock or cash, or a combination of stock and cash. During 2022, 2021 and 2020, only shares of common stock were used to settle all vested RSUs. The Company expects to settle RSUs that vest in the future using shares of common stock.

RSUs currently outstanding relate to the 2022 and 2021 grants. RSUs granted to employees are a long-term compensation component, that vest ratably over an approximate three year period subject to service conditions through each vesting date. See the table below for anticipated vesting by year of outstanding RSU grants.

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:

	2022		2021		2020	
	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Unit	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Unit	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, beginning of period	698,465	$ 4.71	763,688	$ 4.51	1,614,722	$ 5.73
Granted	984,394	6.24	710,441	4.71	—	—
Vested[1]	(387,285)	5.20	(731,095)	4.51	(787,203)	6.90
Forfeited	(74,113)	5.24	(44,569)	4.50	(63,831)	5.80
Nonvested, end of period	1,221,461	5.76	698,465	$ 4.71	763,688	$ 4.51

(1) During May and June 2022, approximately 22,000 outstanding RSUs awarded in 2021 to two individuals retiring from their employment with the Company were modified to fully vest upon their retirement, which occurred during May and June 2022, respectively. The remaining unrecognized grant date fair value of the original RSUs was recognized over the requisite period. The incremental cost due to the modification was not materially different from the grant date fair value.

RSUs fair value at grant date –The grant date fair value of RSUs granted during 2022 and 2021 was $6.1 million and $3.3 million, respectively. There were no RSUs granted during 2020.

RSUs fair value at vested date – The fair value of the RSUs that vested during 2022, 2021 and 2020 was $1.9 million, $2.4 million and $2.0 million, respectively, based on the Company's closing price on the vesting date.

For the outstanding RSUs issued to the eligible employees as of December 31, 2022, vesting is expected to occur as follows (subject to forfeitures):

	Restricted Shares
2023	470,750
2024	470,699
2025	280,012
Total	1,221,461

Performance Share Units ("PSUs")

During 2022 and 2021, the Company granted PSUs under the Plan to certain of its employees. There were no PSUs granted in 2020. 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 for 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 currently outstanding relate to 2022 and 2021 grants.

PSUs granted to employees in 2022 are subject to an approximate three year performance period and service conditions through the vesting date. The performance period for the 2022 PSU grants ends on December 31, 2024 with vesting occurring on January 1, 2025.

PSUs granted to employees in 2021 were subject to an approximate one year performance period which ended on December 31, 2021. Subsequent to the performance period, the PSUs continue to be subject to service-based criteria until vesting occurring on October 1, 2023.

A summary of activity related to PSUs is as follows:

	2022		2021	
	Performance Share Units	Weighted Average Grant Date Fair Value Per Unit	Performance Share Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, beginning of period	196,918	$ 5.55	—	$ —
Granted	1,384,214	10.29	393,073	5.56
Vested [(1)]	(15,264)	5.57	—	—
Forfeited	(63,629)	8.84	(196,155)	5.57
Nonvested, end of period	1,502,239	9.78	196,918	$ 5.55

(1) During May and June 2022, approximately 12,000 outstanding PSUs awarded in 2021 to two individuals retiring from their employment with the Company were modified to fully vest upon their retirement, which occurred during May and June 2022, respectively. The remaining unrecognized grant date fair value of the original PSUs was recognized over the requisite period. The incremental cost due to the modification was not materially different from the grant date fair value.

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 highly subjective assumptions. Key assumptions in the method include 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. 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:

	2022 Grant Date May 26, 2022	2021 Grant Date June 28, 2021
Expected term for performance period (in years)	2.6	0.5
Expected volatility	84.4 %	67.9 %
Risk-free interest rate	2.5 %	0.1 %
Fair value (in thousands)	$ 14,240	$ 1,852

PSUs fair value at vested date – The fair value of the PSUs that vested during 2022 was $0.1 million. No PSUs vested during 2021 and 2020.

For the outstanding PSUs issued to the eligible employees as of December 31, 2022, vesting is expected to occur as follows (subject to forfeitures):

	Performance Shares
2023	161,418
2024	—
2025	1,340,821
Total	1,502,239

Share-Based Awards: Restricted Stock

Under the Directors Compensation Plan, shares of restricted stock ("Restricted Shares") were issued in 2022, 2021 and 2020 to the Company's non-employee directors as a component of their compensation arrangement. Vesting occurs upon completion of the one year vesting period. The holders of Restricted Shares 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. Restricted Shares are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restriction period.

As of December 31, 2022, there were 368,316 shares of common stock available for issuance in satisfaction of awards under the Directors Compensation Plan. Reductions in shares available are made when Restricted Shares are granted.

A summary of activity related to Restricted Shares is as follows:

	2022		2021		2020	
	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, beginning of period	70,226	$ 3.65	154,128	$ 3.64	123,180	$ 4.55
Granted	42,426	4.95	62,502	3.36	109,376	2.56
Vested	(70,226)	3.65	(146,404)	3.51	(78,428)	2.38
Nonvested, end of period	42,426	$ 4.95	70,226	$ 3.65	154,128	$ 3.64

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2022 are eligible to vest in 2023.

Restricted stock fair value at grant date - The grant date fair value of restricted stock granted during 2022, 2021 and 2020 was $0.2 million, $0.2 million and $0.3 million, respectively, based on the Company's closing price on the date of grant.

Restricted stock fair value at vested date - The fair value of the restricted stock that vested during 2022, 2021 and 2020 was $0.4 million, $0.5 million and $0.2 million, respectively, based on the Company's closing price on the date of vesting.

Share-Based Compensation

A summary of compensation expense under share-based payment arrangements is as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Restricted stock units	$ 4,192	$ 2,579	$ 3,555
Performance share units	3,504	412	—
Restricted Shares	226	373	404
Total	$ 7,922	$ 3,364	$ 3,959

As of December 31, 2022, unrecognized share-based compensation expense related to our awards of RSUs, PSUs and Restricted Shares was $2.4 million, $9.9 million and $0.1 million, respectively. Unrecognized compensation expense will be recognized through December 2024 for RSUs and PSUs and April 2023 for Restricted Shares.

Cash-based Incentive Compensation

Short-term Cash-Based Incentive Compensation

The following short-term cash-based incentive awards were granted during 2022 and 2021:

- On May 26, 2022 the Company granted cash based awards subject to Company performance criteria. As of December 31, 2022, a portion of the Company performance based criteria was achieved. As of December 31, 2022, incentive compensation expense of $11.9 million was recognized related to these awards. Payment is expected to be made in March 2023.

- In February 2021, the Company granted discretionary cash-based awards subject only to continued employment on the payment dates. The 2021 discretionary bonus award was paid in equal installments on March 15, 2021 and April 15, 2021, to substantially all employees subject to employment on those dates. Incentive compensation expense of $7.0 million was recognized as of December 31, 2021, related to these awards.

- During June 2021, the Company granted cash-based awards subject to Company performance criteria through December 31, 2021. A portion of the Company performance-based criteria were achieved. In addition, the Board of Directors approved a discretionary amount. Incentive compensation expense of $2.1 million and $6.4 million was recognized in 2022 and 2021, respectively, related to these awards. Payments were made in March 2022.

No cash-based incentive awards were granted in 2020. Cash-based incentive compensation expense recorded in 2020 related to the amortization of long-term cash awards granted in prior periods.

Long-term Cash-Based Incentive Compensation

No long-term cash-based incentive awards were granted during the year ended December 31, 2022.

During June 2021, the Company granted long-term, cash-based awards (the “2021 Cash Awards”) subject to the same performance-based criteria as the 2021 PSUs noted above. The 2021 Cash Awards were subject to an approximate one year performance period, which ended on December 31, 2021. Subsequent to the performance period, the 2021 Cash Awards will continue to be subject to service-based criteria until vesting occurring on October 1, 2023.

The 2021 Cash Awards are accounted for as liability awards and are measured at fair value each reporting date through the end of the performance period. Compensation cost for the 2021 Cash Awards to employees is recognized over the service period from June 28, 2021 through October 1, 2023. The fair value of the awards as of December 31, 2022 is $1.1 million. During the year ended December 31, 2022 and 2021, the Company recognized expense of $0.5 million and $0.2 million related to the 2021 Cash Awards. As of December 31, 2022, unrecognized compensation expense related to these awards was $0.4 million.

Share-Based Awards and Cash-Based Awards Compensation Expense

A summary of compensation expense related to share-based awards and cash-based awards is as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Share-based compensation included in:			
General and administrative expenses	$ 7,922	$ 3,364	$ 3,959
Cash-based incentive compensation included in:			
Lease operating expense[1]	3,812	3,500	849
General and administrative expenses[1]	10,697	10,086	4,019
Total charged to operating income (loss)	$ 22,431	$ 16,950	$ 8,827

(1) Includes adjustments of accruals to actual payments.

NOTE 12 — 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 2022, 2021, and 2020 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 $2.4 million, $2.0 million, and $2.3 million for 2022, 2021 and 2020, respectively.

NOTE 13 — INCOME TAXES

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2022	2021	2020
Current	$ 8,476	$ 132	$ 134
Deferred	45,184	(8,189)	(30,287)
Total income tax expense (benefit)	$ 53,660	$ (8,057)	$ (30,153)

Reconciliation

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) is as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Income tax expense (benefit) at the federal statutory rate	$ 59,810	$ (10,402)	$ 1,604
Compensation adjustments	599	559	1,373
State income taxes	2,418	(330)	75
Impact of U.S. legislative changes	—	—	(21,345)
Valuation allowance	(9,117)	1,863	(12,018)
Other	(50)	253	158
Total income tax expense (benefit)	$ 53,660	$ (8,057)	$ (30,153)

The Company's effective tax rate for the years 2022, 2021 and 2020 differed from the applicable federal statutory rate of 21.0% primarily due to adjustments in the valuation allowance on deferred tax assets, which is discussed below, and the impact of state income taxes. As a result, the effective tax rate for 2022 and 2021 is 18.8% and 16.3%, respectively, while the effective tax rate for the year 2020 is not meaningful.

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,	
	2022	2021
Deferred tax liabilities:		
Property and equipment	$ 80,616	$ 55,170
Investment in non-consolidated entity	3,951	4,659
Other	2,948	2,817
Total deferred tax liabilities	87,515	62,646
Deferred tax assets:		
Derivatives	25,969	21,026
Asset retirement obligations	103,910	91,850
Contingent asset retirement obligations	4,540	980
Right of use liability	2,964	2,976
Federal net operating losses	281	42,127
State net operating losses	5,691	7,612
Interest expense limitation carryover	9,620	18,628
Share-based compensation	1,546	312
Valuation allowance	(15,311)	(24,359)
Other	5,513	3,886
Total deferred tax assets	144,723	165,038
Net deferred tax assets	$ 57,208	$ 102,392

Income Taxes Receivable, Refunds and Payments

As of December 31, 2022 and 2021, the Company did not have any current income taxes receivable. During the year ended December 31, 2022 the Company made $8.2 million in income tax payments, and during the year ended December 31, 2021, the Company did not make any tax payments of significance.

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, 2022 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 1,339	N/A
State net operating loss	96,054	2026-2041
Interest expense limitation carryover	43,139	N/A

Valuation Allowance

During 2022, the Company's valuation allowance decreased $9.0 million primarily due to the utilization of part of the Company's disallowed interest expense limitation carryover. 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 2022 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). As of December 31, 2022, the Company's valuation allowance was $15.3 million.

Years Open to Examination

The tax years from 2019 through 2022 remain open to examination by the tax jurisdictions to which the Company is subject.

NOTE 14 — EARNINGS PER SHARE

The Company's unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are deemed participating securities and are included in the computation of earnings per share under the two-class method when the effect is dilutive.

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

	Year Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 231,149	$ (41,478)	$ 37,790
Weighted average common shares outstanding - basic	143,143	142,271	141,622
Dilutive effect of securities	1,947	—	1,655
Weighted average common shares outstanding - diluted	145,090	142,271	143,277
Earnings per common share:			
Basic	$ 1.61	$ (0.29)	$ 0.26
Diluted	$ 1.59	$ (0.29)	$ 0.26
Shares excluded due to being anti-dilutive (weighted average)	—	1,370	—

NOTE 15 — SUPPLEMENTAL CASH FLOW INFORMATION

The following table reflects supplemental cash flow information (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Supplemental cash items:			
Cash and cash equivalents	$ 461,357	$ 245,799	$ 43,726
Restricted cash and restricted cash equivalents	4,417	4,417	—
Cash paid for interest	71,126	64,805	59,183
Cash paid for income taxes	8,198	152	159
Cash refunds received for income taxes	—	1	2,007
Cash received for interest income	5,909	112	603
Non-cash investing activities:			
Accruals of property and equipment	6,636	9,464	3,035
ARO - additions, dispositions and revisions, net	91,652	36,175	17,928

NOTE 16 — 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, or 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, 2022, the Company had surety bonds related to the agreement totaling $100.4 million and had no amounts in escrow. The threshold escalates to $103.0 million for 2023. 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, 2022, 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, 2022. This amount increases on June 1 of the following years to $40.0 million - 2023; $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. W&T 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, W&T 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.

During 2022, 2021 and 2020, the Company had surety bonds primarily related to decommissioning obligations. Total expenses related to surety bonds, inclusive of the surety bonds in connection with the agreements described above, were $8.3 million, $6.0 million, and $5.4 million during 2022, 2021 and 2020, respectively. Future surety bond costs may change due to a number of factors, including changes and interpretations of regulations by the BOEM, rates being charged in the market place, and timing of when decommissioning 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 to 2028. For 2022, 2021 and 2020 expense recognized for the difference between the quantities shipped and the minimum obligations was $1.6 million, $2.1 million and $4.5 million, respectively.

The Company does not have any long-term drilling rig commitments as of December 31, 2022.

NOTE 17 — RELATED PARTIES

During 2022, 2021 and 2020, there were certain transactions between W&T and other companies W&T's Chief Executive Officer, Tracy W. Krohn ("CEO") either controlled or in which he had an ownership interest.

The Company's CEO owns an aircraft that the Company used for business purposes and the CEO used for his personal matters pursuant to his employment contract, and these costs were paid by the Company. Airplane services transactions were approximately $1.7 million, $0.6 million and $0.3 million for the each of the years ended December 31, 2022, 2021 and 2020.

An entity owned by the Company's CEO has legacy ownership interests in certain wells operated by W&T. Revenues are disbursed and expenses are collected in accordance with ownership interest. As of December 31, 2022, such wells have been plugged and abandoned by the operator. The entity also has ownership interests in certain wells in which the Company does not have an ownership interest in. These wells are covered under W&T'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 W&T for certain administrative costs incurred during the year. These costs are less than $0.1 million per year and are included on the Company's Consolidated Statements of Operations as a reduction to general and administrative expenses. All ownership interests noted above pre-date the Company's initial public offering.

A company that provides marine transportation and logistics services to W&T employs the spouse of the Company's CEO. The rates charged for these marine and transportation services were generally either equal to or below rates charged by non-related, third-party companies and/or otherwise determined to be of the best value to the Company. Payments to such company totaled $20.0 million, $12.0 million and $14.4 million in 2022, 2021 and 2020, respectively. The spouse received commissions partially based on services rendered to W&T which were approximately $0.1 million in 2022, 2021 and 2020.

During 2018, an entity controlled by the Company's CEO participated in the 9.75% Senior Second Lien Note issuance for an $8.0 million principal commitment on the same terms as the other lenders.

During 2022 and 2021, pursuant to the Amendments to the Sixth Amended and Restated Credit Agreement, Calculus, an entity indirectly owned and controlled by W&T's CEO, became the sole lender under the Credit Agreement. In relation to the execution of the Ninth, Tenth and Eleventh Amendments, the Company paid Calculus 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 Calculus of approximately $0.1 million and $0.2 million in 2022 and 2021, respectively. See *Note 2 – Debt* for information on the related party transaction concerning Calculus. In addition, during the year ended December 31, 2022 and 2021, Calculus earned commitment fees of $1.5 million and $1.0 million, respectively, equal to 3.0% of the unused borrowing base lending commitment.

See *Note 5 – Joint Venture Drilling Program* for information on a related party transaction concerning Monza. See *Note 20 – Subsequent Events* for additional information regarding related party transactions which occurred subsequent to December 31, 2022.

NOTE 18 — CONTINGENCIES

Appeal with ONRR

In 2009, W&T 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 in 2010, ONRR notified the Company that they had disallowed approximately $4.7 million of the reductions taken. The Company recorded a reduction to other revenue in 2010 to reflect this disallowance with the offset to a liability reserve; however, the Company disagrees with the position taken by the ONRR. W&T filed an appeal with the ONRR, which ultimately led to the Company posting a bond in the amount of $7.2 million and cash collateral of $6.9 million with the surety in order to appeal the Interior Board of Land Appeals decision. The cash collateral held by the surety was subsequently returned to the Company during the first quarter of 2020. The Company has continued to pursue its legal rights and 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. W&T 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. In compliance with the ONRR's request for W&T to post surety, the sum of the bond posted is currently $8.5 million.

Civil Penalties Assessment

In January 2021, the Company executed a Settlement Agreement with BSEE which resolved nine pending civil penalties issued by BSEE which pertained to INCs alleging regulatory non-compliance at separate offshore locations on various dates between July 2012 and January 2018, with the proposed civil penalty amounts totaling $7.7 million. Under the Settlement Agreement, W&T will pay a total of $720,000 in three annual installments. The first, second and final installments were paid in March 2021, March 2022 and February 2023, respectively. In addition, W&T committed to implement a Safety Improvement Plan with various deliverables due, which have all been timely satisfied .

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, W&T 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. W&T no longer owns these assets nor are they related to current operations. During the year ended December 31, 2021, as a result of the declaration of bankruptcy by a third party that is the indirect successor in title to certain offshore interests that were previously divested by the Company, W&T recorded a $4.5 million loss contingency accrual related to the anticipated decommissioning obligations reflected in *Other expense (income)* on the Consolidated Statements of Operations. During the year ended December 31, 2022, the Company recorded an additional $15.4 million loss contingency accrual related to the anticipated decommissioning obligations reflected in *Other expense (income)* on the Consolidated Statements of Operations. 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, W&T intends to seek contribution from other parties that owned an interest in the facilities.

AAIT Litigation

In August 2022, the Company’s primary information technology service provider, AAIT, notified the Company of its intention to cease providing services to the Company by September 2, 2022. Following such notification, the Company began the process of moving certain of these services within the Company and transitioning the remaining services to new service providers. On August 19, 2022, the Company filed in the District Court of Harris County, Texas a petition for a temporary restraining order, temporary injunction, and permanent injunction seeking, among other things, to restrain AAIT from ceasing to provide services to the Company until the transition process is complete. On September 14, 2022, AAIT removed the matter to the United States District Court for the Southern District of Texas. On September 16, 2022, the Company and AAIT mutually agreed to the terms of an agreed order of the court providing for a temporary injunction for a period of a minimum of 60 days from the date of the order and up to a maximum of 120 days at the Company’s option, during which AAIT would continue to provide information technology services to the Company and assist with the transition process. By agreement of the parties, the agreed order also provided for the appointment of Hon. Gregg J. Costa (Ret.) as an independent adjudicator to assist in adjudicating ongoing disputes between the parties. As of December 31, 2022, the Company has substantially completed the transition process and the Company no longer has a material relationship with AAIT.

Other Claims

W&T 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, W&T has indemnified the sellers of properties acquired, and in other cases, W&T 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 W&T 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 19 — 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,		
	2022	2021	2020
Net capitalized costs:			
Proved oil and natural gas properties and equipment	$ 8,813,404	$ 8,636,408	$ 8,567,509
Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities	(8,088,271)	(7,981,271)	(7,890,889)
Net capitalized costs related to producing activities	$ 725,133	$ 655,137	$ 676,620
Depreciation, depletion and amortization ($/Boe)	7.32	6.50	6.34

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,		
	2022	2021	2020
Costs incurred: (1)			
Proved properties acquisitions	$ 78,565	$ 2,197	$ 8,118
Exploration (2)	24,498	18,444	7,727
Development	77,282	47,218	23,528
Total costs incurred in oil and gas property acquisition, exploration and development activities	$ 180,345	$ 67,859	$ 39,373

(1) Includes net additions from capitalized ARO of $88.8 million, $36.2 million, and $15.2 million during 2022, 2021, and 2020, respectively. These adjustments for ARO are associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.

(2) Includes seismic costs of $5.6 million, $0.1 million, and $0.3 million incurred during 2022, 2021, and 2020, respectively. Includes geological and geophysical costs charged to expense of $5.5 million, $5.7 million, and $4.5 million during 2022, 2021, and 2020, respectively.

Oil and Natural Gas Reserve Information

All of the Company’s proved reserves are located in state and federal waters in the U.S. Gulf of Mexico. 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 reserves are located in the United States with all located in state and federal waters in the Gulf of Mexico. The reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information. 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 estimated quantities of net proved oil, NGLs and natural gas reserves:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)
Proved reserves as of December 31, 2019	37.8	24.5	571.1	157.4
Revisions of previous estimates	(0.9)	(5.9)	31.6	(1.4)
Extensions and discoveries	0.2	—	0.2	0.2
Purchase of minerals in place	0.7	0.5	14.8	3.6
Sales of minerals in place	—	—	—	—
Production	(5.6)	(1.7)	(48.4)	(15.4)
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
Extensions and discoveries	—	—	—	—
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
Extensions and discoveries	—	—	—	—
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
Year-end proved developed reserves:				
2022	31.1	17.6	576.0	144.8
2021	27.6	17.8	549.2	137.0
2020	24.0	16.5	550.2	132.2
Year-end proved undeveloped reserves:				
2022[10]	9.5	1.3	58.6	20.5
2021	9.6	1.3	58.4	20.6
2020	8.2	0.9	19.1	12.2

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.

During 2020, decreases in revisions of previous estimates were primarily due to additions made in the Mobile Bay properties due to the consolidation of the Yellowhammer and OTF gas plants which significantly reduced field lease operating expenses and additions made in the Garden Banks 783 (Magnolia) field. These additions were offset due to significant negative revisions due to SEC price revisions for all proved reserves. Proved reserves were also added as a result of working interest acquisitions in both the Mobile Bay Properties and Garden Banks 783 (Magnolia) field.

The Company believes that it will be able to develop all but 2.5 MMBoe (approximately 12%) of the total 20.5 MMBoe classified as PUDs at December 31, 2022, within five years from the date such PUDs were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field ("Matterhorn") and Viosca Knoll 823 ("Virgo") deepwater fields where future development drilling has been planned as sidetracks of existing wellbores due to conductor slot limitations and rig availability. Two sidetrack PUD locations, one each at Matterhorn 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 the latest reserve report, these PUD locations are expected to be developed in 2024.

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 thousands):

	Year Ended December 31,		
	2022	2021	2020
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 8,855,730	$ 5,178,215	$ 2,561,189
Future costs:			
Production	(2,894,652)	(2,061,752)	(1,257,421)
Development and abandonment	(990,329)	(976,500)	(707,357)
Income taxes	(1,005,917)	(358,954)	(60,503)
Future net cash inflows before 10% discount	3,964,832	1,781,009	535,908
10% annual discount factor	(1,701,871)	(625,019)	(42,202)
Total	$ 2,262,961	$ 1,155,990	$ 493,706

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

	December 31,		
	2022	2021	2020
Oil ($/Bbl)	$ 91.50	$ 65.25	$ 37.78
NGLs ($/Bbl)	41.92	26.83	10.29
Natural gas ($/Mcf)	6.85	3.68	2.05

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 thousands):

	Year Ended December 31,		
	2022	2021	2020
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 1,155,990	$ 493,706	$ 986,900
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(672,665)	(370,456)	(168,563)
Net changes in price, net of future production costs	1,368,626	980,922	(503,676)
Extensions and discoveries, net of future production and development costs	—	—	2,767
Changes in estimated future development costs	(18,617)	(25,357)	(15,881)
Previously estimated development costs incurred	3,313	613	1,384
Revisions of quantity estimates	249,117	289,637	(65,218)
Accretion of discount	138,077	43,993	111,760
Net change in income taxes	(369,307)	(181,795)	87,713
Purchases of reserves in-place	225,205	319	44,621
Sales of reserves in-place	—	—	—
Changes in production rates due to timing and other	183,222	(75,592)	11,899
Net (decrease) increase	1,106,971	662,284	(493,194)
Standardized measure, end of year	$ 2,262,961	$ 1,155,990	$ 493,706

NOTE 20 — SUBSEQUENT EVENTS

11.75% Senior Second Lien Notes due 2026

On January 27, 2023, the Company issued and sold $275 million in aggregate principal amount of its 11.75% Senior Second Lien Notes at par with an interest rate of 11.75% per annum that matures on February 1, 2026 (the "11.75% Senior Second Lien Notes"), which are governed under the terms of an indenture (the "Indenture"). Interest on the 11.75% Senior Second Lien Notes is payable in arrears on February 1 and August 1, commencing August 1, 2023. The 11.75% Senior Second Lien Notes will be recorded at their carrying value consisting of principal and unamortized debt issuance costs. The 11.75% Senior Second Lien Notes are secured by second-priority liens on the same collateral that is secured under the Credit Agreement.

Prior to August 1, 2024, the Company may redeem all or any portion of the 11.75% Senior Second Lien Notes at a redemption price equal to 100% of the principal amount of the 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% Senior Second Lien Notes in an amount not greater than the net cash proceeds from certain equity offerings at a redemption price of 111.750% 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% Senior Second Lien 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% Senior Second Lien Notes are guaranteed by the Guarantors.

The 11.75% Senior Second Lien 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% Senior Second Lien Notes an investment grade rating and no default exists with respect to the 11.75% Senior Second Lien Notes.

An entity controlled by the Company's CEO participated in the issuance of the 11.75% Senior Second Lien Notes for a $21.0 million principal commitment, on the same terms as the other lenders.

Redemption of 9.75% Senior Second Lien Notes due 2023

On February 8, 2023, the Company redeemed all of the existing 9.75% Senior Second Lien Notes outstanding at a redemption price of 100.0%, plus accrued and unpaid interest to the redemption date. As of December 31, 2022, there was $552.5 million of aggregate principal outstanding. The Company used the net proceeds of $270.8 million from the issuance of the 11.75% Senior Second Lien Notes and cash on hand of $296.1 million to fund the redemption.

As part of the redemption of the 9.75% Senior Second Lien Notes, an entity controlled by the Company's CEO had their previously disclosed $8.0 million principal commitment repaid in full.

Credit Agreement

On February 8, 2023, the Company provided notice of the redemption of the existing 9.75% Senior Second Lien Notes and the issuance of the 11.75% Senior Second Lien Notes to Alter Domus (US) LLC and Calculus pursuant to the terms of the Credit Agreement, which reaffirmed the Credit Agreement's maturity date of January 3, 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, 2022. 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, 2022 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, 2022, 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, 2022.

The effectiveness of our internal control over financial reporting as of December 31, 2022 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, 2022 which is included under Part II, Item 8 in this Form 10-K.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2022, we moved information technology processes and controls which had been managed by a third party vendor to Company personnel. We hired additional personnel during the second half of the year to transition and take on the information technology management responsibilities. The transition was substantially competed in the fourth quarter. The information technology infrastructure, processes and controls have remained consistent and the change was associated to the personnel managing and overseeing the process and controls.

There were no other 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

None.

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.

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.

2. Exhibits:

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006 (File No. 001-32414))
3.2	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc., dated as of September 6, 2016 (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed September 6, 2016 (File No. 001-32414))
3.4	Third Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.4 of the Company's Current Report on Form 8 K, filed August 8, 2022 (File No. 001 32414))
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 (File No. 001 32414))
4.2	Form of 11.750% Senior Second Lien Note due 2026 (included in Exhibit 4.1 hereto)
4.3	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 (File No. 001-32414))
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 (File No. 333-115103))
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 (File No. 001-32414))
10.4+	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 (File No. 001-32414))

10.5+	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 (File No. 001-32414))
10.6+	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 (File No. 001-32414))
10.7+	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 (File No. 001-32414))
10.8+	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 (File No. 001-32414))
10.9+	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 (File No. 001-32414))
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 (File No. 001-32414))
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 (File No. 001-32414))
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 (File No. 001-32414))
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 (File No. 001-32414))
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 (File No. 001-32414))
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-Kfor 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 (File No. 001-32414))
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 (File No. 001-32414))
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 (File No. 001-32414))
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 (File No. 001-32414)).
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 11, 2022)).
10.26	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 (File No. 001-32414)).
10.27	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 (File No. 001-32414)).
10.28+	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 (File No. 001-32414)).
10.29+	Form of Restricted Stock Unit Agreement (Performance-based Vesting), pursuant to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q, filed August 8, 2022 (File No. 001-32414)).
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.
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.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, on March 8, 2023.

W&T OFFSHORE, INC.

By: /S/ JANET YANG

Janet Yang
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 8, 2023.

/S/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)
/S/ JANET YANG **Janet Yang**	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

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%
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. 333-126252) pertaining to the W&T Offshore, Inc. 2004 Directors Compensation Plan,

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

(5) Registration Statement (Form S-8 No. 333-238210) pertaining to the W&T Offshore, Inc. 2004 Directors Compensation Plan

of our reports dated March 8, 2023, 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, 2022.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 8, 2023

Exhibit 23.2

NSA 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 8, 2023, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated January 26, 2023, 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, 2022", and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2018, 2019, 2020 and 2021. We further consent to the incorporation by reference of information contained in our report dated January 26, 2023, in the Registration Statements (Form S-3 Nos. 333-260248 and 333-214168) of W&T Offshore, Inc. and in the Registration Statements (Form S-8 No. 333-219747) pertaining to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, as amended and the Registration Statements (Form S-8 Nos. 333-126252 and 333-238210) pertaining to the W&T Offshore, Inc. 2004 Directors 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 8, 2023

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 8, 2023

/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, Janet Yang, 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 8, 2023

/s/ Janet Yang
Janet Yang
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 or her knowledge, that the Company's Annual Report on Form 10-K for the year ended December 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 8, 2023

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

Date: March 8, 2023

/s/ Janet Yang
Janet Yang
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

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

January 26, 2023

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, 2022, to the W&T Offshore, Inc. (W&T) proportional consolidation 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.

The net reserves and future net revenue to the W&T proportional consolidation interest have been estimated incorporating the terms of the Monza Joint Venture (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 proportional consolidation interest in these properties, as of December 31, 2022, to be:

	Net Reserves			Future Net Revenue[1] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	23,685.2	16,099.2	499,204.8	3,813,203.1	2,280,776.2
Proved Developed Non-Producing	7,469.9	1,548.5	76,780.8	848,488.8	457,611.2
Proved Undeveloped	9,476.3	1,278.2	58,572.2	775,786.9	390,210.1
Total Proved	40,631.4	18,925.9	634,557.8	5,437,178.8	3,128,597.6

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 the operator'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 2021. For oil and NGL volumes, the average West Texas Intermediate spot price of $94.14 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $6.357 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. Average adjusted product prices weighted by production over the remaining lives of the properties are $91.50 per barrel of oil, $41.92 per barrel of NGL, and $6.846 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/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Executive Chairman

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

Date Signed: January 26, 2023

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

Date Signed: January 26, 2023

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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
> *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

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

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
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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.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
> - *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.