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, 2021

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)***

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common 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. ☑

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 $453,247,467 based on the closing sale price of $4.85 per share as reported by the New York Stock Exchange on June 30, 2021.

The number of shares of the registrant's common stock outstanding on February 28, 2022 was 143,012,124.

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 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact included in this report, 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 involve risks, uncertainties and assumptions. 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.

All statements, other than statements of historical fact included in this report are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future.

These 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. 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 Securities and Exchange Commission ("SEC"). 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.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry that may be used in this Annual Report on Form 10-K.

Acquisitions. Refers to acquisitions, mergers or exercise of preferential rights of purchase.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

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

Bcfe. One billion cubic feet equivalent, determined using an energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

Boe. Barrel of oil equivalent.

Boe/d. Barrel of oil equivalent per day.

BOEM. Bureau of Ocean Energy Management. The agency is responsible for managing development of the nation’s offshore resources in an environmentally and economically responsible way.

BSEE. Bureau of Safety and Environmental Enforcement. The agency is responsible for enforcement of safety and environmental regulations.

Conventional shelf well. A well drilled in water depths less than 500 feet.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths greater than 15,000 feet and water depths of less than 500 feet.

Deepwater. Water depths greater than 500 feet in the Gulf of Mexico.

Deterministic estimate. Refers to a method of estimation whereby a single value for each parameter in the reserves calculation is used in the reserves estimation procedure.

Developed reserves. Oil and natural gas 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.

Development project. A project 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.

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 field or 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 and/or stratigraphic condition.

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

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

MBoe. One thousand barrels of oil equivalent.

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

Mcfe. One thousand cubic feet equivalent, determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil or other hydrocarbon.

Mcfe/d. One thousand cubic feet equivalent per day.

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.

MMcfe. One million cubic feet equivalent, determined using an energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil condensate or natural gas liquids.

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. Also, referred to as the Henry Hub Index.

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 assumed the functions of the former Minerals Revenue Management Program, which had been renamed to the Bureau of Ocean Energy Management, Regulation and Enforcement.

Probabilistic estimate. Refers to a method of estimation whereby the full range of values that could reasonably occur for each unknown parameter in the reserves estimation procedure is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

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

Proved properties. Properties with proved reserves.

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

PV-10. A term used in the industry that is not a defined term in generally accepted accounting principles. We define PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs. PV-10 excludes cash flows for asset retirement obligations, general and administrative expenses, derivatives, debt service and income taxes.

Reasonable certainty. When deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities of hydrocarbons will be recovered. When probabilistic methods are used, reasonable certainty means at least a 90% probability that the quantities of hydrocarbons 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, engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

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

Reliable technology. 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.

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

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.

Sub-salt. A geological layer lying below the salt layer.

Undeveloped reserves. Oil and natural gas 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. 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 production at greater distances. 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. 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, or by other evidence using reliable technology establishing reasonable certainty.

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 exploration, development and acquisition 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. We currently hold working interests in 43 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"), as described in more detail in *Financial Statements and Supplementary Data – Note 5 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K.

We have developed significant technical expertise in finding and developing properties in the Gulf of Mexico with production rates which provide the best opportunity to achieve a rapid return on our invested capital. We have leveraged our experience in the conventional shelf to develop higher impact capital projects in the Gulf of Mexico in both the deepwater and the deep shelf. We have acquired rights to explore and develop new prospects and existing oil and natural gas properties in both the deepwater and the deep shelf, while at the same time continuing our focus on the conventional shelf. Our drilling efforts in recent years have included the deepwater of the Gulf of Mexico.

Business Strategy

Our goal is to pursue risk-adjusted, 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, thus enhancing the value of our assets. We intend to execute the following elements of our business strategy in order to achieve this goal:

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

Our focus is on making profitable investments while operating within cash flow, maintaining sufficient liquidity, achieving prudent cost reductions and fulfilling our contractual, legal and financial obligations. Over time, we expect to de-lever through free cash flow generated by our producing asset base, organic growth opportunities and acquisitions. We continually monitor current and forecasted commodity prices to assess if changes are needed to our plans.

Market Trends

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 cash flows are materially impacted by the prices of commodities we produce (crude oil, natural gas and the natural gas liquids ("NGLs")). In addition, the prices of goods and services used in our business can vary and impact our cash flows.

During 2021, commodity prices experienced significant improvement, particularly crude oil prices, due to a confluence of factors that have provided positive developments to the overall pricing environment when compared to 2020. With some exceptions, pandemic-related travel restrictions have gradually eased as governments continue to have increasing access to vaccines that help reduce the spread of COVID-19. As restrictions continue to abate, there is renewed emphasis on improving economic activity to pre-pandemic levels while managing the risk of a resurgence in COVID-19. Meanwhile, commodity prices demonstrated resiliency during the year. Producers continued to show restraint in increasing their capital expenditures even as prices increased, thereby causing a muted response in supply as demand for commodities increased. Additionally, OPEC Plus remained committed to modest increases in production during the year as the global economy recovered.

While the current outlook for commodity prices is favorable and our operations are no longer significantly impacted by confinement restrictions, the risk of disruption to our operations continues as the emergence of a new variant of COVID-19 could adversely impact our operations, or commodity prices could significantly decline from current levels. The ongoing COVID-19 outbreak continues to evolve and, during the fourth quarter of 2021, a new variant emerged, the Omicron variant. It is difficult to assess if it will cause meaningful disruptions in economic activity across the world and if there will be any significant impacts in demand for energy.

The recent invasion of parts of Ukraine by Russia, and the impact of world sanctions against Russia and the potential for retaliatory acts from Russia, are world events that can result in potential commodities and securities market disruptions that could affect world oil and natural gas markets and the volatility of oil and gas commodity prices and thus impact the Company's business, stock trading price and availability of capital. Additionally, while OPEC Plus remained committed to steady and predictable production increases throughout 2021, it is difficult to determine whether it will change its production output policy or whether its members will remain committed to the production quotas set by the organization as a result of these events.

Our margins in 2021 decreased from 2020 primarily due to realized derivative gains in 2020 compared to realized derivative losses in 2021, partially offset by higher average realized commodity prices in 2021 compared to 2020. We measure margins using net (loss) income before net interest expense; income tax (benefit) expense; depreciation, depletion, amortization and accretion; unrealized commodity derivative gain or loss; amortization of derivative premiums; bad debt reserve; gain on debt transaction; release of restricted funds; litigation; and other ("Adjusted EBITDA") as a percent of revenue, which is a not a financial measurement under generally accepted accounting principles ("GAAP").

Our total production decreased 9.6% in 2021 from the prior year. Our proved reserves increased by 13.2 million barrels of oil equivalent ("MMBoe") in 2021, primarily due to the significant increase in commodity prices in 2021 as compared to 2020.

We continually monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2022 plans. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 in this Form 10-K for additional information.

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. However, in 2021, approximately 34% of our revenues were received from BP Products North America, 14% from Chevron-Texaco and 11% from Williams Field Services, with no other customer comprising greater than 10% of our 2021 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, as 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. The Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("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 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). 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 over $1.0 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 gases ("GHGs"), 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 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 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. 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.

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. In the federal government's most recent list of potential regulatory actions for 2022, the BSEE lists its plans to propose rules finalizing the policies and procedures concerning compliance with OCS oil and gas decommissioning obligations originally proposed under the Trump Administration. In addition, BOEM lists its plans to propose a new rule in respect of financial assurance. 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. 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.

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 costs, and the BOEM typically relies upon the BSEE's estimates to set the amount of required bonds or other forms of financial security in order to minimize the government's perceived risk of potential decommissioning liability.

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 exercises its authority either by applying cost-of-service principles or granting market based 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 British thermal units ("MMBtu") 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, 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.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past 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, several groups have filed litigation over this December 2020 final action, and the Biden Administration has announced plans to reconsider the December 2020 final action in favor of a more stringent ground-level ozone NAAQS.

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 and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level. Under the Biden Administration, however, 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 from certain new, modified or reconstructed facilities in the oil and natural gas sector. Compliance with these rules or other similar rules implemented in the future could result in increased compliance costs on our operations. In November 2021, the EPA also issued a proposed rule that would more stringently regulate methane emissions from crude oil and natural gas sources. The EPA plans to issue a supplemental proposal enhancing this proposed rulemaking in 2022 with the goal of issuing a final rule by the end of 2022. Additionally, state implementation of revised air emission standards could result in stricter permitting requirements, delaying, limiting or prohibiting our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

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,” to which President Biden recommitted the Unites States, thereby requiring the United States to determine its emissions reduction goals every five years after 2020. The international community also gathered in Glasgow in November 2021 at the 26th Conference of the Parties (“COP26”), at which the United States and European Union jointly announced the launch of a Global Methane Pledge, an initiative which over 100 counties joined, committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including “all feasible reductions” in the energy sector. 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.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risk regarding climate change. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. We are not currently a defendant in any of these lawsuits but could be named in actions making similar allegations.

Additionally, our access to capital may be impacted by climate change policies. Stockholders and bondholders currently invested in fossil fuel energy companies such as ours but concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices that favor "clean" power sources, such as wind and solar, making those sources more attractive, and 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. Additionally, there is the possibility that financial institutions will be pressured or required to adopt policies that limit funding for fossil fuel energy companies.

The OCSLA authorized the DOI to regulate activities authorized by the BOEM in the Central and Western Gulf of Mexico. The EPA has air quality jurisdiction over all other parts of the OCS. Under the OCSLA, 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. 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 liable "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 joint and several, strict liability, without regard to fault, to each liable 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 release 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 $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. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. In addition, Federal Lease Stipulations include regulations regarding the taking of lives of protected marine species (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”). This law prohibits 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 notably clarifies that criminal liability under the Migratory Bird Treaty Act (“MBTA”) will 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. Additionally, the USFWS may make determinations on the listing of species as threatened or endangered under the ESA 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 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 Mammal Protection 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 or wetlands. These and other protected areas may require certain mitigation measures to avoid harm to wildlife, and such laws and regulations may impose substantial liabilities for pollution resulting from 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.

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 delays the installation of production facilities, thereby delaying production and sales of our oil and natural gas.

Inflation. Although inflation in the United States has been relatively low in recent years, it rose significantly in the second half of 2021. This is believed to be the result of the economic impact from the COVID-19 pandemic, including the global supply chain disruptions, among other factors. For 2021, our realized prices for crude oil increased 71.5%, NGLs increased 171.6% and natural gas increased 89.0% from 2020. Historically, our operating costs have moved directionally with the price of crude oil, NGLs and natural gas, as these commodities affect the demand for these goods and services, but the timing of such increases and decreases may lag behind changes in commodity prices. However, global, industry-wide supply chain disruptions caused by the COVID-19 pandemic have also resulted in shortages in labor, materials and services which have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase as well as scarcity of certain products and raw materials. We are experiencing some inflationary pressure for certain costs, including employees and vendors, although such cost increases did not materially impact our 2021 financial condition or results of operations, and we currently do not expect them to materially impact our 2022 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

People are our most valuable asset, and we strive to provide a work environment that attracts and retains the top talent in the industry, reflects our core values and demonstrates our core values to the communities in which we operate.

As of December 31, 2021, our personnel base consisted of 323 of our employees and over 330 individuals who are employees of third parties that provide skilled labor in support of our field operations. This combined workforce conducts our business in Texas, Alabama 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 and the Gulf of Mexico are primarily composed of skilled labor who conduct our field operations and manage third party personnel used in support of our field operations. We focus on certain measures and objectives when managing our workforce that are material in understanding our business, which are summarized below:

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 2021 total recordable incident rate ("TRIR") for employees was 0.32, which is far below the industry average for the Gulf of Mexico of 1.01. Our Health, Safety and Environmental ("HS&E") group is comprised of a Vice President, and Environmental, Safety and Regulatory Managers and 9 staff personnel. The Department 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.

As a company identified by the Federal Government as essential to the critical infrastructure of the United States, we have continuously operated during the COVID-19 pandemic. To provide our personnel with a physically safer work environment and mitigate the risks associated with the transmission of COVID-19, we implement policies requiring mandatory face masks and social distancing in all work environments, conduct daily temperature screening at all locations and COVID-19 testing for field project crews.

Recruitment 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. Global, industry-wide supply chain disruptions caused by the COVID-19 pandemic have resulted in shortages in labor, which have resulted in inflationary cost increases for labor and could continue to cause costs to increase. If these conditions continue, it could result in increased wages to retain existing employees and impact what we offer prospective employees in the future in order to remain competitive.

Diversity and Inclusion. 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 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, 2021:

Category	Female	Male
Exec/Sr. Manager	20 %	80 %
Mid-Level Manager	21 %	79 %
Professionals	48 %	52 %
All Other	12 %	88 %

US Ethnicity	Exec/ Sr. Manager	Mid-Level Manager	Professionals	All Other
Asian	40 %	9 %	11 %	1 %
Black/African American	20 %	6 %	20 %	5 %
Hispanic/Latino	—	2 %	9 %	6 %
Native American	—	—	—	1 %
Two or more races	—	—	—	1 %
White	40 %	83 %	60 %	86 %

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 the Organization of Petroleum Exporting Countries ("OPEC") and other major oil producing countries ("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 recent invasion of parts of Ukraine by Russia);
- domestic and foreign governmental regulations and taxes;
- 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;
- 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, NGL and natural gas pricing. While we have not recorded an impairment of our oil and gas properties during the year-ended December 31, 2021, 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 hurricanes which could reduce or eliminate our ability to market our production. As of December 31, 2021, four fields, accounting for approximately 0.3 MMBoe (or 2.5%) of our 2021 production, are tied back to separate, third-party owned 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 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 27.3% of our total proved reserves as of December 31, 2021 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, and we may not be able 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. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Insurance Coverage* under Part II, Item 7 in this Form 10-K for additional information on insurance coverage.

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.

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 hurricanes.

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.

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.

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, 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 hurricane 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.

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, 2021.

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 will 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.

The COVID-19 pandemic has affected, and may continue to materially adversely affect, our industry, business, financial condition or results of operations.

The COVID-19 pandemic and related economic repercussions have created significant volatility, uncertainty, and turmoil in the oil and gas industry. The COVID-19 outbreak and the responsive actions to limit the spread of the virus significantly reduced global economic activity in 2020 and 2021, resulting in a decline in the demand for oil, natural gas, and other commodities. As COVID-19 vaccines have been more widely distributed, global economic activity is improving and commodity prices are currently above pre-pandemic levels. However, the energy markets remain subject to heightened levels of volatility and uncertainty as responses to COVID-19 and COVID-19 variants continue to evolve. Disruptions in global demand for oil and natural gas caused by the COVID 19 pandemic may continue to affect us, constraining our ability to store and move production to downstream markets, or affecting future decisions to delay or curtail development activity or temporarily shut-in production which could further reduce cash flow. We will continue to monitor the effects of the pandemic on energy markets in the future.

The extent of the impact of the COVID-19 pandemic and any other future pandemic on our business will depend on the nature, spread and duration of the disease, the responsive actions to contain its spread or address its effects, its effect on the demand for oil and natural gas, the timing and severity of the related consequences on commodity prices and the economy more generally, including any recession resulting from the pandemic, among other things. Any extended period of depressed commodity prices or general economic disruption as a result of the pandemic would adversely affect our business, financial conditions and results of operations. In addition, the COVID-19 pandemic has heightened the other risks and uncertainties described in this report.

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 parts of Ukraine by Russia, and the impact of world sanctions against Russia and the potential for retaliatory acts from Russia, could result in increased cybersecurity attacks against U.S. companies.

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

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

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, 2021, we had 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, 2023. The Senior Second Lien Notes mature on November 1, 2023.

Our leverage and debt service obligations could:

- increase our vulnerability to general adverse economic and industry conditions, including reduced demand during the COVID-19 pandemic;
- limit our ability to fund future working capital requirements, capital expenditures and ARO, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets;
- limit our opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt obligations or to comply with any restrictive terms of our debt obligations;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

- limit or impair our ability to obtain additional financing or refinancing in the future or require us to seek alternative financing, which may be more restrictive or expensive; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations. If new debt is added to our current debt levels, the related risks that we face could intensify. Additionally, availability of borrowings and letters of credit under our Credit Agreement is determined by establishment of a borrowing base, which is periodically redetermined in lender's sole discretion based on our 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.

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, 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 our 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 Second Lien Senior Notes are secured by various liens on our oil, natural gas and NGL properties, excluding our Mobile Bay properties. Our 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 Second Lien Term 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 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 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.

We may be unable to provide the 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.

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. As of the filing date of this Form 10-K, we are in compliance with our financial assurance obligations to the BOEM and have no outstanding BOEM orders, requests or financial assurance obligations. The 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, the BOEM could in the future make new demands for additional financial assurances covering our obligations under our properties, which could exceed the Company's capabilities to provide. If we fail to comply with such future orders, the 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, 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.

The threat of climate change 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.

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. As a result, our operations are subject to a series of 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 and restriction of GHG emissions. The adoption and implementation of any international, federal, regional or state legislation, executive actions, regulations 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, political, financial and litigation risks may result in us having to restrict, delay or cancel production activities, incur liability for infrastructure damages as a result of climatic changes, or impair the ability to continue to operate in an economic manner, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. Increasing attention to climate change, increasing societal expectations on companies to address climate change, and potential customer use of substitutes to energy commodities may result in increased costs, reduced demand for oil and natural gas we produce, resulting in reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. 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. Finally, 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.

Increasing attention to Environmental, Social and Governance (“ESG”) matters may impact our business.

Increasing attention to climate change, societal expectations for companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for the oil and natural gas we produce, reduced profits, increased risks of governmental investigations and private party litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts from oil and natural gas products and bias against companies operating in the sector. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

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. Throughout 2021, we undertook several initiatives to improve our ESG performance. From an environmental perspective, we consolidated the gas processing operations for our Mobile Bay assets which lowered our greenhouse gas emissions related to the operation of those assets. On the social front, we instituted a company-wide diversity training program and tied completion of that program to our short-term compensation for the year. Relating to governance, we continued to assess the various competing ESG frameworks; executive management and the Board are evaluating the appropriate oversight and management policies and procedures that would allow us to continue to strengthen our ESG performance. 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.

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.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

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, 2021, two of our fields located in the conventional shelf accounted for approximately 71.6% our proved reserves on an energy equivalent basis. The following table provides information for these fields:

	Proved Reserves as of December 31, 2021				
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Percent of Total Company Proved Reserves
Mobile Bay Properties	0.2	14.8	466.1	92.7	58.8 %
Ship Shoal 349 (Mahogany)	13.9	1.1	31.6	20.2	12.8 %

The Mobile Bay Properties and Ship Shoal 349 (Mahogany) 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

The Mobile Bay Properties (including the Fairway field) consist of interests located off the coast of Alabama, in state coastal and federal Gulf of Mexico waters approximately 70 miles south of Mobile, Alabama. During 2021, we consolidated the Fairway field into the Mobile Bay Properties in conjunction with the Mobile Bay Transaction as described in *Financial Statements and Supplementary Data – Note 4 - Mobile Bay Transaction* under Part II, Item 8 in this Form 10-K. The field area includes 17 Alabama state water lease blocks and four Federal OCS lease blocks. These properties include seven major platforms and 21 flowing wells, in up to 50 feet of water.

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 2021 is approximately 843.9 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, 2021, 56 Norphlet wells have been drilled on the Mobile Bay Properties, 45 of which were successful and 27 of which are currently producing.

As we did not acquire the majority of the Mobile Bay Properties until the end of August 2019, the results of operations were not included within our Consolidated Results of Operations until September 1, 2019. Given the limited history of the full combined Mobile Bay Properties and Fairway field, production volumes, realized prices received and production costs are not presented for 2019.

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

	Year Ended December 31,	
	2021	2020
Net Sales:		
Oil (MBbls)	29	9
NGLs (MBbls)	998	1,167
Natural gas (MMcf)	32,940	34,793
Total oil equivalent (MBoe)	6,516	6,975
Average realized sales prices:		
Oil ($/Bbl)	$ 27.49	$ 38.52
NGLs ($/Bbl)	30.84	10.34
Natural gas ($/Mcf)	3.92	2.08
Oil equivalent ($/Boe)	24.68	12.18
Average production costs: (1)		
Oil equivalent ($/Boe)	$ 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. Phillips Petroleum Company discovered the field in 1993. 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 (“Apache”) 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 2021 is approximately 59.3 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, 2021, 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. During 2018, one well was completed which had been drilled to target depth during 2017, and in addition, two wells were drilled and completed during 2018. During 2019, one well was drilled, completed and producing in 2019, and significant workover activities were done to increase production. There has been no additional 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,		
	2021	**2020**	**2019**
Net Sales:			
Oil (MBbls)	1,667	1,939	2,444
NGLs (MBbls)	88	148	154
Natural gas (MMcf)	2,565	3,015	3,955
Total oil equivalent (MBoe)	2,182	2,590	3,257
Average realized sales prices:			
Oil ($/Bbl)	$ 65.27	$ 36.69	$ 58.27
NGLs ($/Bbl)	36.85	14.46	21.96
Natural gas ($/Mcf)	4.00	1.92	2.53
Oil equivalent ($/Boe)	56.05	30.54	47.84
Average production costs: [1]			
Oil equivalent ($/Boe)	$ 6.60	$ 4.98	$ 4.77

(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, 2021, 2020 and 2019 are summarized below:

Classification of Proved Reserves (1)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	MMBoe(2)	% of Total Proved	PV-10 (In millions)
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
December 31, 2019						
Proved developed producing	24.0	20.2	469.2	122.3	78 %	$ 992.0
Proved developed non-producing	4.0	1.5	35.7	11.5	7 %	95.0
Total proved developed	28.0	21.7	504.9	133.8	85 %	1,087.0
Proved undeveloped	9.8	2.8	66.2	23.6	15 %	215.5
Total proved	37.8	24.5	571.1	157.4	100 %	$ 1,302.5

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2021 were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the year end December 31, 2021. Applying this methodology, the West Texas Intermediate ("WTI") average spot price of $66.55 per barrel and the Henry Hub natural gas average spot price of $3.60 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 $65.25 per barrel for oil, $26.83 per barrel for NGLs and $3.68 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.

(2) The conversions to barrels of oil equivalent were determined using the energy equivalence ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs. Totals may not compute due to rounding. The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent price for oil and NGLs may differ significantly.

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,		
	2021	2020	2019
Present value of estimated future net revenues (PV-10)	$ 1,621.9	$ 740.9	$ 1,302.5
Present value of estimated ARO, discounted at 10%	(241.1)	(204.2)	(184.9)
PV-10 after ARO	1,380.8	536.7	1,117.6
Future income taxes, discounted at 10%	(224.8)	(43.0)	(130.7)
Standardized measure	$ 1,156.0	$ 493.7	$ 986.9

Changes in Proved Reserves

The following table discloses our estimated changes in proved reserves during the year ended December 31, 2021:

	MMBoe
Proved reserves at December 31, 2020	144.4
Reserves additions (reductions):	
Revisions(1)	27.1
Extensions and discoveries	—
Purchases of minerals in place	—
Production	(13.9)
Net reserve additions (reductions)	13.2
Total proved reserves at December 31, 2021	157.6

(1) Net revisions of 27.1 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 2021. 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, 2021 are calculated based upon SEC mandated 2021 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 2021 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, 2021 were estimated at $358.3 million.

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

	December 31,		
	2021	2020	2019
Proved undeveloped reserves, beginning of year	12.2	23.6	17.0
Transfers to proved developed reserves	—	—	(0.5)
Revisions of previous estimates	8.4	(11.4)	7.1
Extensions and discoveries	—	—	—
Purchase of minerals in place	—	—	—
Sales of minerals in place	—	—	—
Proved undeveloped reserves, end of year	20.6	12.2	23.6

Activity related to PUD in 2021:

- Net PUD upward revisions of 8.4 MMBoe were primarily due to price revisions at our Ship Shoal 028 and Mahogany fields.

Activity related to PUDs in 2020:

- Net PUD downward revisions of 11.4 MMBoe were primarily due to price revisions at our Ship Shoal 028 and Mahogany fields.

Activity related to PUDs in 2019:

- Successfully drilled and converted two locations and 0.5 MMBoe from PUD to proved developed with total capital expenditures of $27.1 million during 2019.

- Net PUD revisions of 7.1 MMboe were primarily at our Ship Shoal 028 and our Mahogany 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
2022	1	14 %
2023	3	28 %
2024	1	3 %
2025	2	20 %
2026	4	35 %
Total	11	100 %

We believe that we will be able to develop all but 2.5 MMBoe (approximately 12%) of the total 20.6 MMBoe classified as PUDs at December 31, 2021, 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 2023 and 2024.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2021 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 16 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. 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. We convert barrels to Mcfe using an energy-equivalent ratio of six Mcf to one barrel of oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ substantially.

Acreage

The following table summarizes our leasehold at December 31, 2021. Deepwater refers to acreage in over 500 feet of water:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	348,421	272,205	62,604	57,342	411,025	329,547
Deepwater	153,449	61,819	33,394	15,548	186,843	77,367
Alabama State Waters	8,041	5,147	—	—	8,041	5,147
Total	509,911	339,171	95,998	72,890	605,909	412,061

Approximately 82% 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.

Regarding the undeveloped leasehold, of the total 72,890 net undeveloped acres none could expire in 2022; 25,395 net acres (35%) could expire in 2023; 24,662 net acres (34%) could expire in 2024; 11,313 net acres (15%) could expire in 2025; and 11,520 net acres (16%) could expire in 2025 and beyond. In making decisions regarding drilling and operations activity for 2022 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.

Our net acreage decreased 93,815 net acres (19%) from December 31, 2020 due to lease expirations and relinquishments.

Drilling Activity

The table below is based on the SEC's criteria of completion or abandonment to determine wells drilled.

Development and Exploration Drilling

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

	Year Ended December 31,		
	2021	2020	2019
Development Wells Completed:			
Gross wells	—	—	3.0
Net wells	—	—	1.6
Exploration Wells Completed:			
Gross wells	—	—	3.0
Net wells	—	—	0.8

Our success rates related to our development and exploration wells was 100% in 2019, with all wells drilled and completed being productive and none were non-commercial (dry holes).

Drilling Activity

During 2020, we drilled one well, which we completed in March 2022. During 2021, we participated in the drilling of an exploration well which we do not expect to complete.

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, 2021 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	75.0	66.0	67.0	59.0	142.0	125.0
Non-operated	33.0	5.0	3.0	0.5	36.0	5.5
Total offshore wells	108.0	71.0	70.0	59.5	178.0	130.5

(1) Includes eight gross (5.8 net) oil wells with multiple completions.

(2) Includes two gross (1.6 net) gas wells with multiple completions.

Production

For the years 2021, 2020 and 2019, our net daily production averaged 38,117 Boe, 42,046 Boe, and 40,634 Boe, respectively. Production decreased in 2021 from 2020 primarily due to temporary shut-in and deferral of as much as approximately 80% of the Company's production in preparation for, and as a result of, the effects of Hurricane Ida as well as other 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,		
	2021	2020	2019
Net Sales:			
Oil (MBbls)	4,998	5,629	6,675
NGLs (MBbls)	1,450	1,696	1,271
Natural gas (MMcf)	44,790	48,384	41,310
Total oil equivalent (MBoe)	13,913	15,389	14,831

Item 3. ***Legal Proceedings***

Appeal with ONRR. In 2009, we recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited our calculations and support related to this usage fee, and we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance with the offset to a liability reserve; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the Interior Board of Land Appeals ("IBLA") under the DOI. On January 27, 2017, the IBLA affirmed the decision of the ONRR requiring W&T to pay approximately $4.7 million in additional royalties. We filed a motion for reconsideration of the IBLA decision on March 27, 2017. Based on a statutory deadline, we filed an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana. We were required to post a bond in the amount of $7.2 million and cash collateral of $6.9 million in order to appeal the IBLA decision. On December 4, 2018, the IBLA denied our motion for reconsideration. On February 4, 2019, we filed our first amended complaint, and the government has filed its Answer in the Administrative Record. On July 9, 2019, we filed an Objection to the Administrative Record and Motion to Supplement the Administrative Record, asking the court to order the government to file a complete privilege log with the record. Following a hearing on July 31, 2019, the Court ordered the government to file a complete privilege log. In an Order dated December 18, 2019, the court ordered the government to produce certain contracts subject to a protective order and to produce the remaining documents in dispute to the court for *in camera* review. Ultimately, the court upheld the government's assertion of privilege and the parties commenced briefing on the merits. At this point, 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, we are waiting for the district court's ruling on the merits. In January 2020, the cash collateral in the amount of $6.9 million securing the appeal bond in this matter was released to us. In compliance with the ONRR's request for W&T to increase the surety posted in the appeal, the penal sum of the bond posted is currently $8.5 million.

Monetary Sanctions by Government Authorities (Civil Penalty Assessments). In January 2021, we executed a Settlement Agreement with BSEE which resolved nine pending civil penalties issued by BSEE. The civil penalties pertained to INCs issued by BSEE alleging regulatory non-compliance at separate offshore locations on various dates between July 2012 and January 2018, 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 installment was paid in March 2021. In addition, W&T committed to implement a Safety Improvement Plan with various deliverables due over a period ending in 2022. In September 2021, we paid $40,200 related to an INC issued in 2018. Additionally, in September 2021, we were notified of a new proposed civil penalty assessment for $46,000 for an INC that occurred at one of our properties in 2018, which we subsequently paid in January 2022.

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***

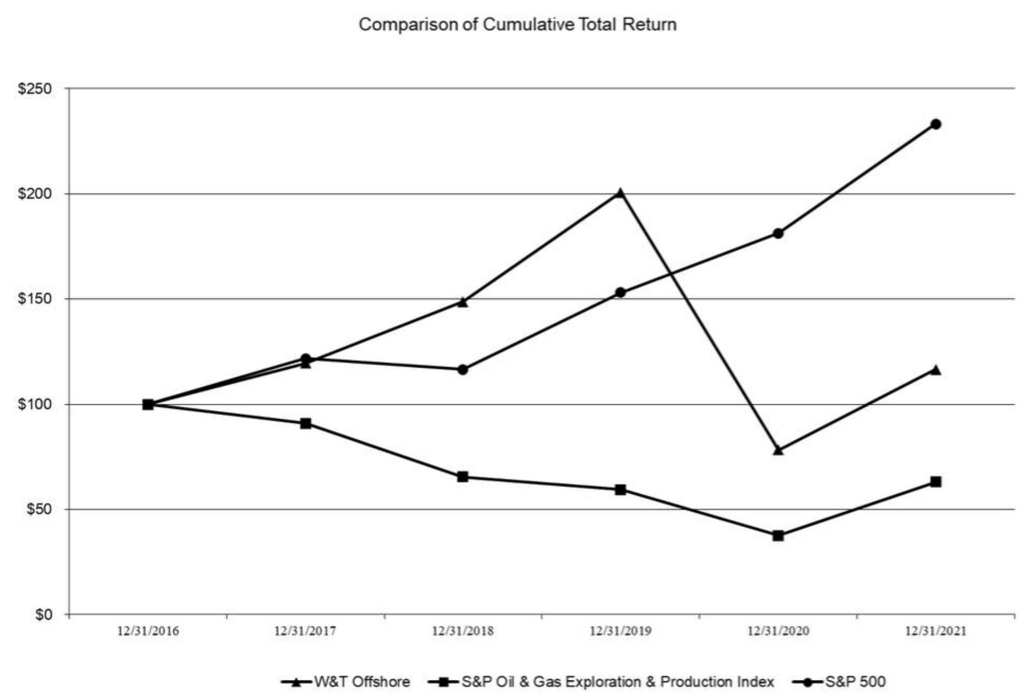
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of March 1, 2022, there were 185 registered holders of our common stock.

Dividends

During 2021 and 2020, 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.



Securities Authorized for Issuance under Equity Compensation Plans

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. For descriptions of the plans and additional information, see *Financial Statements and Supplementary Data – Note 11 –Share-Based Awards and Cash-Based Awards* under Part II, Item 8 in this Form 10-K.

Issuer Purchases of Equity Securities

For the year 2021, we did not purchase any of our equity securities.

The following table sets forth information about restricted stock units ("RSUs") during the quarter ended December 31, 2021:

Period	Total Number of Restricted Stock Units Delivered	Average Price per Restricted Stock Unit	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or) Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
October 1, 2021 – October 31, 2021	N/A	N/A	N/A	N/A
November 1, 2021 - November 30, 2021	N/A	N/A	N/A	N/A
December 1, 2021 – December 31, 2021 (1)	235,855	3.31	N/A	N/A

(1) RSUs delivered by employees during December 2021 to satisfy tax withholding obligations on the vesting of RSU.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2021 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, Items 1 and 2 *Business and 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 Annual Report. 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 Annual Report, particularly in Part I, Item 1A *Risk Factors*.

This section of this Annual Report generally discusses 2021 and 2020 items and year-to-year comparisons between 2021 and 2020. Discussions of 2019 items and year-to-year comparisons between 2020 and 2019 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, 2020.

Overview

We are an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties in the Gulf of Mexico. We have grown through acquisitions, exploration and development and currently hold working interests in 43 offshore producing fields in federal and state waters (38 producing fields and 5 capable of producing). We currently have under lease approximately 606,000 gross acres (412,000 net acres) spanning across the OCS off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 8,000 gross acres in Alabama State waters, 411,000 gross acres on the conventional shelf and approximately 187,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 144 offshore structures, 103 of which are located in fields that we operate. We currently own interest in 178 productive wells, 142 of which we operate. 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, as described in more detail in *Financial Statements and Supplementary Data – Notes 4* and *5* under Part II, Item 8 in this Annual Report.

Business Strategy

Our goal is to pursue 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, thus enhancing the value of our assets. We intend to execute the following elements of our business strategy in order to achieve this goal:

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

Our focus is on making profitable investments while operating within cash flow, maintaining sufficient liquidity, cost reductions and fulfilling our contractual, legal and financial obligations. Over time, we expect to de-lever through free cash flow generated by our producing asset base, capital discipline, organic growth and acquisitions. We continue to closely monitor current and forecasted commodity prices to assess if changes are needed to be made to our plans.

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 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 2021, average realized commodity prices increased from those we experienced during 2020 and 2019. Our margins in 2021 increased from 2020 primarily due to higher average realized commodity prices, partially offset by higher operating expenses as a result of our cost-cutting efforts in 2021. We measure margins using Adjusted EBITDA as a percent of revenue, which is a not a financial measurement under GAAP. We have historically increased our reserves and production through acquisitions, our drilling programs, and other projects that optimize production on existing wells. Our production decreased 9.6% in 2021 from the prior year. Our proved reserves increased by 13.2 MMBoe in 2021, primarily due to the significant increase in commodity prices in 2021 as compared to 2020.

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

Mobile Bay Transaction. During the second quarter of 2021, the Company's wholly-owned special purpose subsidiary vehicles, A-I LLC and A-II LLC (or collectively the "Subsidiary Borrowers"), entered into the Subsidiary Credit Agreement providing for a secured term loan ("Term Loan") in an initial aggregate principal amount equal to $215.0 million. Proceeds of the Term Loan were used by the Subsidiary 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. This transaction is described in more detail under *Financial Statements and Supplementary Data – Note 4 – Mobile Bay Transaction*, under Part II, Item 8, of this Annual Report.

Hurricanes and Severe Weather. During the third quarter of 2021, our production from the U.S 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 $5.8 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 *Liquidity and Capital Resources – Insurance Coverage* under this Item 7 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 has been volatile. 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. As a result, 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.

During 2021, commodity prices experienced significant improvement, particularly crude oil prices, due to a confluence of factors that have provided positive developments to the overall pricing environment when compared to 2020. With some exceptions, pandemic-related travel restrictions have gradually eased as governments continue to have increasing access to vaccines that help reduce the spread of COVID-19. As restrictions continue to abate, there is renewed emphasis on improving economic activity to pre-pandemic levels while managing the risk of a resurgence in COVID-19. Meanwhile, commodity prices demonstrated resiliency during the year. Producers continued to show restraint in increasing their capital expenditures even as prices increased, thereby causing a muted response in supply as demand for commodities increased. Additionally, OPEC Plus remained committed to modest increases in production during the year as the global economy recovered.

While the current outlook for commodity prices is favorable and our operations are no longer significantly impacted by confinement restrictions, the risk of disruption to our operations continues as the emergence of a new variant of COVID-19 could adversely impact our operations, or commodity prices could significantly decline from current levels. The ongoing COVID-19 outbreak continues to evolve and, during the fourth quarter of 2021, a new variant emerged, the Omicron variant. It is difficult to assess if it will cause meaningful disruptions in economic activity across the world and if there will be any significant impacts in demand for energy.

The recent invasion of parts of Ukraine by Russia, and the impact of world sanctions against Russia and the potential for retaliatory acts from Russia, are world events that can result in potential commodities and securities market disruptions that could affect world oil and natural gas markets and the volatility of oil and gas commodity prices and thus impact the Company's business, stock trading price and availability of capital. Additionally, while OPEC Plus remained committed to steady and predictable production increases throughout 2021, it is difficult to determine whether it will change its production output policy or whether its members will remain committed to the production quotas set by the organization as a result of these events.

WTI is frequently used to value domestically produced crude oil, and the majority of 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 $68.14 per barrel during 2021, up from $39.16 barrel during 2020 (74% increase). The U.S. Energy Information Administration (“EIA”) in their Short-Term Energy Outlook issued in January 2022 projects average crude oil prices for WTI to increase to approximately $71.32 per barrel in 2022, and decrease in 2023 to approximately $63.50 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 $3.89 per MMBtu during 2021, up from $2.03 per MMBtu during 2020. The EIA projects average natural gas prices for Henry Hub to decrease to approximately $3.94 per MMBtu in 2022, and decrease further in 2023 to approximately $3.77 per MMBtu. Global oil production is forecasted to outpace global oil consumption during 2022 resulting in rising global oil inventories. Oil market balances are subject to significant uncertainties which could keep oil prices volatile.

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.

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, 2021, the Company’s ceiling test computation was based on SEC pricing of $65.25 per Bbl of oil, $3.68 per Mcf of natural gas and $26.83 per Bbl of NGLs.

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, which we expect to decrease further as a result of sustained lower commodity prices. 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.

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 *Liquidity and Capital Resources – Insurance Coverage* under this Item 7 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. As of the filing date of this Form 10-K, the Company is in compliance with its financial assurance obligations to the 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 the BOEM. 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. 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 2021 or 2020, 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.

Consolidated Appropriations Act, 2021. Under the Consolidated Appropriations Act, 2021 passed by the United States Congress and signed by the President on December 27, 2020, provisions of the CARES Act were extended and modified making the Company eligible for a refundable employee retention credit subject to meeting certain criteria. See *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8, and *Liquidity and Capital Resources* in this Item 7 of this Form 10-K for additional information.

Results of Operations

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

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 income (expense)" in our Consolidated Statements of Operations. The following table presents our sources of revenue as a percentage of total revenue:

	Year Ended December 31,	
	2021	2020
Oil	59.1 %	62.4 %
NGLs	7.9 %	5.5 %
Natural gas	31.1 %	28.7 %
Other	1.9 %	3.4 %

The information below provides a discussion of, and an analysis of significant variance in, our oil, natural gas and NGL revenues, production volumes and sales prices for the years ended December 31, 2021 and 2020 (in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020	Change
	(In thousands, except realized sales price data)		
Revenues:			
Oil	$ 329,557	$ 216,419	$ 113,138
NGLs	44,343	19,101	25,242
Natural gas	173,749	99,300	74,449
Other	10,361	11,814	(1,453)
Total revenues	$ 558,010	$ 346,634	$ 211,376
Production Volumes:			
Oil (MBbls)	4,998	5,629	(631)
NGLs (MBbls)	1,450	1,696	(246)
Natural gas (MMcf)	44,790	48,384	(3,594)
Total oil equivalent (MBoe)	13,913	15,389	(1,476)
Average daily equivalent sales (Boe/day)	38,118	42,046	(3,928)
Average realized sales prices:			
Oil ($/Bbl)	$ 65.94	$ 38.45	$ 27.49
NGLs ($/Bbl)	30.59	11.26	19.33
Natural gas ($/Mcf)	3.88	2.05	1.83
Oil equivalent ($/Boe)	39.36	21.76	17.60
Oil equivalent ($/Boe), including realized commodity derivatives	32.52	24.70	7.82

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, 2021 and 2020 (in thousands):

	Price	Volume	Total
Oil	$ 137,392	$ (24,254)	$ 113,138
NGLs	28,017	(2,775)	25,242
Natural gas	81,826	(7,377)	74,449
	$ 247,235	$ (34,406)	$ 212,829

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 Mahogany 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 Poseidon, LLS and HLS for 2021 declined on average by approximately $0.63 - $1.13 per barrel compared to 2020 for these types of crude oils with the Poseidon having a negative differential and the LLS and HLS having positive differentials as measured on an index basis.

Two major components of our NGLs, ethane and propane, typically make up approximately 70% of an average NGL barrel. During 2021, average prices for domestic ethane increased by 62.7% and average domestic propane prices increased by 125.7% from 2020 as measured using a price index for Mount Belvieu. The changes in the average price for other domestic NGLs components in 2021 ranged from an increase of 100.9% to 103.7% 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 decreased by 1,476 MBoe to 13,913 MBoe primarily due to adverse weather events during the 3rd quarter of 2021, well maintenance and natural declines. Deferred production for 2021 related to these named storms and maintenance events collectively resulted in deferred production of 2.2 MMBoe, compared to 2.8 MMBoe in 2020.

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, 2021	Year Ended December 31, 2020	Change
	(In thousands, except per Boe data)		
Operating expenses:			
Lease operating expenses	$ 174,582	$ 162,857	$ 11,725
Production taxes	10,074	4,918	5,156
Gathering and transportation	17,845	16,029	1,816
Depreciation, depletion, amortization and accretion	113,447	120,284	(6,837)
Ceiling test write-down of oil and natural gas properties	—	—	—
General and administrative expenses	52,400	41,745	10,655
Total operating expenses	$ 368,348	$ 345,833	$ 22,515
Average per Boe ($/Boe):			
Lease operating expenses	$ 12.55	$ 10.58	$ 1.97
Gathering and transportation	1.28	1.04	0.24
Production costs	13.83	11.62	2.21
Production taxes	0.72	0.32	0.40
DD&A	8.15	7.82	0.33
G&A expenses	3.77	2.71	1.06
Operating costs	$ 26.47	$ 22.47	$ 4.00

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 $11.7 million to $174.6 million in 2021 compared to $162.9 million in 2020. On a per Boe basis, lease operating expenses increased to $12.55 per Boe during 2021 compared to $10.58 per Boe during 2020. On a component basis, base lease operating expenses increased $5.0 million, workover expenses increased $1.8 million, facilities maintenance expenses increased $4.9 million, and hurricane repairs increased $1.0 million. These increases were partially offset by decrease of $1.0 million in insurance premiums.

Expenses for direct labor, materials and supplies, rental and third party costs comprise the most significant portion of our base lease operating expense. Base lease operating expenses increased primarily due to (i) a net increase in contract labor, equipment rental, and transportation costs of $3.6 million at various fields; (ii) increased incentive compensation costs related to field employees of $2.2 million; (iii) a reduction in credits to expense from prior period royalty adjustments of $1.5 million as compared to the prior period; and (iv) a reduction in credits to expense of $2.3 million received in prior period from the PPP funds; partially offset by (v) $4.6 million of reduced expenses related to fields that were no longer producing during the year ended December 31, 2021, cost savings from the consolidation of our two gas processing plants in Alabama, and other miscellaneous items.

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.

Production taxes. 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. Production taxes were $10.1 million in 2021, an increase of $5.2 million as compared to 2020, primarily due to the increase in realized natural gas prices, partially offset by decreased natural gas production volumes.

Gathering and transportation costs. Gathering and transportation costs consist of costs incurred in the post-production shipping of oil, NGLs, and natural gas to the point of sale. Gathering and transportation costs increased to $17.8 million in 2021 compared to $16.0 million in 2020 primarily due to lower costs in the prior year that were impacted by credits to expense associated with the finalization of the Mobile Bay acquisition.

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 $8.15 per Boe in 2021 from $7.82 per Boe in 2020. On a nominal basis, DD&A decreased to $113.4 million in 2021 from $120.3 million in 2020. The rate per Boe increased year-over-year mostly as a result of increases in the future development costs included in the depreciable base compared to the relatively 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 2021, G&A expenses were $52.4 million compared to $41.7 million in 2020. The increase in 2021 G&A expense compared to 2020 was primarily due to (i) a net increase of $4.4 million increase in legal costs and other miscellaneous expenses primarily related to credits to expense in the prior period to adjust for the final settlement of BEE civil penalties; (ii) a net increase of $3.4 million in payroll and incentive compensation expenses as share based compensation expense and cash incentive compensation expense did not occur in the prior period; (iii) a reduction in overhead allocations to partners (credits to expense) of $0.7 million; (iv) credits related to the PPP funds received in the prior period; partially offset by (v) the $2.1 million employee retention credit recognized during the first quarter of 2021. See *Financial Statements – Note 1 – Basis of Presentation* under Part 1, Item 1, and Liquidity and Capital Resources in this Item 2 of this Quarterly Report for additional information on the employee retention credit.

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, 2021	2020 (In thousands)	Change
Other income and expenses:			
Derivative loss (gain)	$ 175,313	$ (23,808)	$ 199,121
Interest expense, net	70,049	61,463	8,586
Gain on debt transactions	—	(47,469)	47,469
Other (income) expense, net	(6,165)	2,978	(9,143)
Income tax (benefit) expense	(8,057)	(30,153)	22,096

Derivative loss (gain). We utilize commodity derivative instruments to reduce our exposure to fluctuations in the price of oil and natural gas. We recognize gains and losses associated with our open commodity derivative contracts as commodity prices and the associated fair value of our commodity derivative contracts change. The commodity derivative contracts we have in place are not designated as hedges for accounting purposes. Consequently, these commodity derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. Changes in the fair value and settlements are recorded on the Consolidated Statements of Operations in *Derivative loss (gain)* as an unrealized loss (gain) and a realized loss (gain), respectively. Additionally, we amortize derivative cash premiums paid for options over the life of the related contract on the Consolidated Statements of Operations in *Derivative loss (gain)* as a component of realized loss.

During 2021, a $175.3 million derivative loss was recorded for crude oil and natural gas derivative contracts. Of the total derivative loss, approximately $80.1 million and $95.2 million were associated with the unrealized loss and realized loss, respectfully. The realized derivative loss recorded in 2021 includes approximately $5.1 million of derivative premium amortization. The remaining realized derivative loss and unrealized derivative loss were primarily due to crude oil and natural gas prices rising throughout 2021 as compared to prices as of December 31, 2020, which decreased the estimated fair value of open contracts and decreased the settlement value of closed contracts. During 2020, a $23.8 million derivative gain was recorded for crude oil and natural gas derivative contracts. The total derivative gain includes a $33.4 million realized derivative gain offset by a $9.6 million unrealized derivative loss. The realized derivative gain recorded in 2020 was primarily due to crude oil prices falling during the second quarter of 2020 to historic lows, which increased the settlement value of closed contracts; the realized derivative gain was offset by $1.9 million of derivative premium amortization. The unrealized derivative loss in 2020 is primarily due to crude oil prices rising in the latter months of 2020, which decreased the estimated fair value of open 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 $70.0 million in 2021, increasing $8.7 million from $61.5 million in 2020. The increase is primarily due to interest expense on the principal balance of the Term Loan, lower interest income between the two periods, and a reduction in credits to interest expense related to the PPP funds received in the prior period; partially offset by reductions to outstanding borrowings (lower interest expense) under the Credit Agreement during 2021 and a full year of reduced interest on the lower principal balance of the Senior Second Lien Notes. 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.

Gain on debt transactions. During 2020, the repurchase of a portion of our Senior Second Lien Notes resulted in a gain of $47.5 million for 2020. *See Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information.

Other (income) expense, net. During 2021, other income, net, was $6.2 million, compared to $3.0 million of other expense, net, for 2020. 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. For 2020, the amount primarily consisted of expenses related to 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 benefit (expense). Our income tax benefit for 2021 and 2020 was $8.1 million and $30.2 million, respectively. For 2021, our annual effective tax rate of 16.3% differed from the federal statutory rate of 21% primarily due to changes in our valuation allowance on our interest expense limitation carryover. Our effective tax rate for 2020 was not meaningful, and our income tax benefit was primarily due to the enactment of the Coronavirus Aid, Relief and Economic Security Act ("Cares Act") on March 27, 2020 and the issuance by the United States Treasury Department (Treasury) of final and proposed regulations under Internal Revenue Code ("IRC") Section 163(j) on July 28, 2020 that provided additional guidance and clarification to the business interest expense limitation.

During 2021, our valuation allowance increased $2.0 million primarily due to an increase in our 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 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 our ability to realize our 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. Although the Company incurred a loss in 2021, we determined that these results were not indicative of future results and concluded that the positive evidence outweighed the 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, charitable contributions carryover and the disallowed interest limitation carryover under IRC section 163(j). As of December 31, 2021, the Company's valuation allowance was $24.4 million.

Liquidity and Capital Resources

Liquidity Overview

Our primary uses of cash are for capital expenditures, working capital, debt service and for general corporate purposes. We fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings, make related interest payments 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 borrowings.

The primary sources of our liquidity are cash from operating activities and borrowings under our Credit Agreement. As of December 31, 2021, we had $245.8 million of available cash and $50.0 million available under our Credit Agreement, based on a borrowing base of $50.0 million. Subsequent to December 31, 2021, we have agreed to an extension of the Credit Agreement with Calculus Lending until January 3, 2023. See discussion in *Credit Agreement* below.

We believe that we will have adequate liquidity from cash flow from operations to fund our capital expenditure plans for 2022, fund our ARO spending for 2022 and fulfill our various other obligations. Availability under our Credit Agreement as of December 31, 2021 was $50.0 million. Our preliminary capital expenditure budget for 2022 has been established in the range of $70.0 million to $90.0 million, which includes our share of the Joint Venture Drilling Program, and excludes acquisitions. In our view of the outlook for 2022, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2022 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 prices improve, we may increase our investments. Beyond 2022, while we expect to continue to have adequate liquidity from cash flow from operations to fulfill our future obligations, we continue to evaluate financing and refinancing alternatives on a strategic basis.

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, 2021	2020	Change
	(In thousands)		
Operating activities	$ 133,668	$ 108,509	$ 25,159
Investing activities	(27,444)	(47,616)	20,172
Financing activities	100,266	(49,600)	149,866

Operating activities. Net cash provided by operating activities for 2021 was $133.7 million, increasing $25.2 million from 2020. The change between periods is primarily due to increased realized prices for crude oil, NGLs and natural gas, partially offset by decreased volumes, increased derivative settlement payments, and increased spending for ARO activities. Our combined average realized sales price per Boe increased 80.9% in 2021, which caused total revenues to increase $247.2 million, partially offset by decreases of 9.6% in overall production volumes which caused revenues to decrease by $34.4 million.

Other items affecting operating cash flows for 2021 were: ARO settlements of $27.3 million, which increased from $3.3 million in 2020; cash advances from joint venture partners of $7.8 million during 2021 compared to $2.0 million during 2020; derivative cash payments, net, were $81.3 million in 2021 compared to derivative cash receipts, net, of $45.2 million in 2020; and derivative premiums of $40.5 million were paid in 2021.

Investing activities. Net cash used in investing activities during 2021 and 2020 was $27.4 million and $47.6 million, respectively, which represents our acquisitions and investments in oil and gas properties and equipment. Investments in oil and natural gas properties (including changes in operating assets and liabilities associated with investing activities) during 2021 decreased $17.4 million from 2020 primarily due to less capital projects being undertaken in 2021 as compared to 2020. During 2020, the acquisition of property interest of $2.9 million was primarily related to the additional working interest acquisitions at the Mobile Bay Properties and Magnolia field. There were no significant acquisitions in 2021. There were no asset sales of significance in 2021 or 2020. See discussion in *Capital Expenditures* below.

Financing activities. Net cash provided by financing activities for 2021 was $100.3 million and net cash used in financing activities for 2020 was $49.6 million. During 2021, net cash provided by financing activities included the proceeds from the Term Loan of $215.0 million, offset by $9.8 million of debt issue costs incurred related to the Term Loan and the Ninth Amendment to the Credit Agreement, the repayment of $80.0 million of borrowings under the Credit Agreement and repayments of $24.1 million of the Term Loan. During 2020, net cash used in financing activities was from repayments of funds borrowed under the Credit Agreement and the purchase of the Senior Second Lien Notes, offset by borrowings under the Credit Agreement. The purchase of the Senior Second Lien Notes are disclosed in *Financial Statements and Supplementary Data - Note 2 – Debt* under Part II, Item 8 in this Form 10-K.

Joint Venture Drilling Program. To provide additional financial flexibility, we created the Joint Venture Drilling Program with private investors during 2018. The Joint Venture Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in certain drilling projects. It also allows more projects to be taken on with our capital expenditures budget and reduces our risk via diversification. In the Joint Venture Drilling Program, four wells came on line during 2018 and five came on line during 2019. During 2020, one well was drilled, which we completed in March 2022. See *Financial Statements and Supplementary Data – Note 5 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K for additional information on the Joint Venture Drilling 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 and interest rate risk from floating interest rates on our revolving bank credit facility. During 2021 and 2020, we entered into commodity contracts for crude oil and natural gas which related to a portion of our expected production for the time frames covered by the contracts. As of December 31, 2021, we had outstanding open derivatives for crude 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. The following table summarizes the historical results of our realized hedging activities:

	Year Ended December 31,	
	2021	**2020**
Crude Oil ($/Bbl):		
Average realized sales price, before the effects of derivative settlements	$ 65.94	$ 38.45
Effects of realized commodity derivatives	(10.44)	6.48
Average realized sales price, including realized commodity derivatives	$ 55.50	$ 44.93
Natural Gas ($/Mcf)		
Average realized sales price, before the effects of derivative settlements	$ 3.88	$ 2.05
Effects of realized commodity derivatives	(0.96)	(0.05)
Average realized sales price, including realized commodity derivatives	$ 2.92	$ 2.00

Income taxes. As of December 31, 2021, we have current income taxes payable of $0.1 million. During 2021, we did not receive any income tax refunds. For 2021, we did not make any significant income tax payments. Additionally, we do not anticipate making any significant tax payments for 2022.

Dividends. During 2021, 2020 and 2019, we did not pay any dividends and a suspension of dividends remains in effect.

Discretionary Bonus to Employees Approved in February 2021. On February 15, 2021, the Company received approval from the Compensation Committee of the Board of Directors for the one-time payment of a discretionary cash bonus in the amount of $7.0 million, paid in equal installments on March 15, 2021 and April 15, 2021, subject to employment on those dates.

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 CARES 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 which is included as a credit to General and administrative expenses in the Consolidated Statement of Operations.

Capital Expenditures

Our preliminary capital expenditure budget for 2022 has been established in the range of $70.0 million to $90.0 million, which includes our share of the Joint Venture Drilling Program and excludes acquisitions. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments. We have flexibility in our capital expenditure programs as we have no long-term rig commitments and our current commitments with partners are short term.

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,	
	2021	2020
	(In thousands)	
Exploration (1)	$ 18,273	$ 1,837
Development (1)	9,478	11,109
Acquisitions of interests (2)	661	2,919
Seismic and other	4,311	4,686
Investments in oil and gas property/equipment – accrual basis	$ 32,723	$ 20,551

(1) Reported geographically in the subsequent table.
(2) Various working interest acquisitions in 2020 and 2021 including the purchase of additional working interest at the Magnolia field the Mobile Bay Properties during 2020.

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

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Conventional shelf (1)	$ 7,872	$ 10,247
Deepwater	19,879	2,699
Exploration and development capital expenditures – accrual basis	$ 27,751	$ 12,946

(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.

The following table sets forth our drilling activity for completed wells on a gross basis:

	Completed		
	2021	2020	2019
Offshore – gross wells drilled:			
Conventional shelf	—	—	3
Deepwater	—	—	3
Wells operated by W&T	—	—	5

We had a 100% success rate in 2019. During 2020, we drilled one well, which we completed in March 2022. All of the wells drilled in 2019 and 2020 are in the Joint Venture Drilling Program. During 2021, we participated in the drilling of an exploration well which we do not plan to complete.

See *Properties – Drilling Activity* under Part I, Item 2 of this Form 10-K for a breakdown of exploration and development wells and additional 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.

Lease Acquisitions. Over the last three years, we have acquired 23 leases for approximately $5.0 million from the BOEM in the Federal Offshore Lease Sales. We acquired 4 leases ($1.2 million) and 17 leases ($3.8 million) in the years 2020 and 2019, respectively. 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 invalidate these leases. We are evaluating the court's opinion and considering our options, which could include participating in an appellate process with peer companies and industry groups. If we are ultimately awarded, we will pay approximately $0.3 million for the awarded leases combined, which reflect a 100% working interest in the acreage.

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 2021 and 2020, there were no property sales of significance. See *Financial Statements and Supplementary Data – Note 6 –Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information on this divestiture.

Asset retirement obligations. Annually, we review and revise our ARO estimates. Our ARO at December 31, 2021 and 2020 were $424.5 million and $392.7 million, respectively, recorded using discounted values. We spent $27.3 million in 2021 and $3.3 million in 2020 for ARO and our estimate of ARO spending in 2022 is $55.0 million to $75.0 million. During 2021 and 2020, 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

We are actively monitoring the debt capital markets, and we intend to seek financings with longer tenors and market based covenants to continue to provide working and potential acquisition capital as well as provide funding for refinancing of some or all of our Second Lien Notes. The terms of such financings, which may replace or augment our Credit Agreement and refinance some or all of our Second Lien Notes, may vary significantly from those under the Credit Agreement and our Second Lien Notes.

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, 2021, we had $190.9 million of Term Loan principal outstanding. The Term Loan requires quarterly amortization payments, bears interest at a fixed rate of 7% 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. See *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information.

Credit Agreement. As of December 31, 2021, we had no borrowings outstanding under the Credit Agreement. During the year ended December 31, 2021, we repaid $80.0 million of borrowings.

On November 2, 2021, the Company entered into two amendments to the Credit Agreement which effectively terminated the Company's existing reserve based lending relationship with commercial bank lenders who have traditionally provided the Company's revolving credit facility and established the Calculus Lending facility under the Credit Agreement. The Company has not had any borrowings under the Credit Agreement since the closing of the Mobile Bay Transaction in May 2021. The Company currently has no borrowings outstanding under the new Credit Agreement. On March 8, 2022 the Company entered into the Tenth Amendment to Sixth Amended and Restated Credit Agreement and Extension Agreement, which extended the maturity date and Lender commitment to January 3, 2023. Generally, we must be in compliance with the covenants in our Credit Agreement in order to access borrowings. See *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 of this Form 10-K for additional information concerning these recent two amendments to the Credit Agreement and the Calculus Lending facility.

Senior Second Lien Notes. As of December 31, 2021, we had $552.5 million principal outstanding of Senior Second Lien Notes with an interest rate of 9.75% per annum that mature on November 1, 2023. The Senior Second Lien Notes are secured by a second-priority lien on all of our assets that are secured under the Credit Agreement. See *Financial Statements and Supplementary Data – Note 2 – Debt* under Part II, Item 8 in this Form 10-K for additional information.

Debt Covenants. The Term Loan, Credit Agreement, and 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 Senior Second Lien Notes. We were in compliance with all applicable covenants of the Term Loan, Credit Agreement and the Senior Second Lien Notes indenture as of and for the period ended December 31, 2021. 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. The See *Financial Statements and Supplementary Data – Note 4 – Mobile Bay Transaction* under Part II, Item 8 in this Annual Report for additional information.

At that time, we designated the Aquasition Entities as unrestricted subsidiaries under Indenture governing Senior Second Lien Notes (the "Unrestricted Subsidiaries"). Having been so designated, the Unrestricted Subsidiaries do not guarantee the 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 Senior Second Lien Notes. 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, 2021 (in thousands):

	Consolidated Balance Sheet	Eliminations of Unrestricted Subsidiaries	Consolidated Balance Sheet of restricted subsidiaries
Assets			
Current assets:			
Cash and cash equivalents	$ 245,799	$ (38,937)	$ 206,862
Restricted cash	4,417	—	4,417
Receivables:			
Oil and natural gas sales	54,919	(34,420)	20,499
Joint interest, net	9,745	10,856	20,601
Total receivables	64,664	(23,564)	41,100
Prepaid expenses and other assets	43,379	(356)	43,023
Total current assets	358,259	(62,857)	295,402
Oil and natural gas properties and other, net	665,252	(272,747)	392,505
Restricted deposits for asset retirement obligations	16,019	—	16,019
Deferred income taxes	102,505	—	102,505
Other assets	51,172	19,903	71,075
Total assets	$ 1,193,207	$ (315,701)	$ 877,506
Liabilities and Shareholders' Deficit			
Current liabilities:			
Accounts payable	$ 82,481	$ (29,678)	$ 52,803
Undistributed oil and natural gas proceeds	36,243	(3,144)	33,099
Asset retirement obligations	56,419	—	56,419
Accrued liabilities	106,140	(29,937)	76,203
Current portion of long-term debt	42,960	(42,960)	—
Income tax payable	133	—	133
Total current liabilities	324,376	(105,719)	218,657
Long-term debt			
Principal	700,359	(147,899)	552,460
Unamortized debt issuance costs	(12,421)	7,546	(4,875)
Long-term debt, net	687,938	(140,353)	547,585
Asset retirement obligations, less current portion	368,076	(54,515)	313,561
Other liabilities	59,884	(42,615)	17,269
Deferred income taxes	113	—	113
Common stock	1	—	1
Additional paid-in capital	552,923	—	552,923
Retained deficit	(775,937)	27,501	(748,436)
Treasury stock, at cost	(24,167)	—	(24,167)
Total shareholders' deficit	(247,180)	27,501	(219,679)
Total liabilities and shareholders' deficit	$ 1,193,207	$ (315,701)	$ 877,506

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, 2021 (in thousands):

	Consolidated	Eliminations of Unrestricted Subsidiaries	Consolidated restricted subsidiaries
Revenues:			
Oil	$ 329,557	$ (463)	$ 329,094
NGLs	44,343	(21,438)	22,905
Natural gas	173,749	(92,863)	80,886
Other	10,361	(4,786)	5,575
Total revenues	558,010	(119,550)	438,460
Operating expenses:			
Lease operating expenses	174,582	(26,507)	148,075
Production taxes	10,074	(6,620)	3,454
Gathering and transportation	17,845	(2,539)	15,306
Depreciation, depletion, amortization and accretion	113,447	3,579	117,026
General and administrative expenses	52,400	(647)	51,753
Total operating expenses	368,348	(32,735)	335,613
Operating (loss) income	189,662	(86,814)	102,848
Interest expense, net	70,049	(9,782)	60,267
Derivative loss (gain)	175,313	(104,533)	70,780
Gain on debt transactions	—	—	—
Other expense, net	(6,165)	—	(6,165)
(Loss) income before income taxes	(49,535)	27,501	(22,034)
Income tax benefit	(8,057)	—	(8,057)
Net (loss) income	$ (41,478)	$ 27,501	$ (13,977)

The following table presents our produced oil, NGLs and natural gas volumes (net to our interests) from the Mobile Bay Properties for the period from May 19, 2021 through December 31, 2021:

	For the period from May 19, 2021 to December 21, 2021
Production Volumes:	
Oil (MBbls)	13
NGLs (MBbls)	603
Natural gas (MMcf)	20,417
Total oil equivalent (MBoe)	4,019
Average realized sales prices:	
Oil ($/Bbl)	$ 35.64
NGLs ($/Bbl)	35.55
Natural gas ($/Mcf)	4.55
Oil equivalent ($/Boe)	28.56
Average production costs[1]:	
Oil equivalent ($/Boe)	$ 7.23

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

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

Insurance Coverage

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 current policy is effective for one year beginning June 1, 2021 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 all 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. Included within the $162.5 million aggregate limit is TLO coverage on our Mahogany platform, which has no retention. The operational and named windstorm coverages are effective for one year beginning June 1, 2021. Coverage for pollution causing a negative environmental impact is provided under the well control and other sections within the policy.

Our general and excess liability policies are effective for one year beginning May 1, 2021 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 do not carry business interruption insurance.

The premiums for the above policies including brokerage fees were $9.7 million for the May/June 2021 policy renewals compared to $10.9 million for the expiring policies. The change in our premiums effective with the May/June 2020 renewal was primarily attributable to negotiations.

Contractual Obligations

At December 31, 2021, we did not have any financing leases. The following table summarizes our significant contractual obligations by maturity as of December 31, 2021 (in millions):

	Payments Due by Period as of December 31, 2021				
	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt – principal	$ 743.3	$ 43.0	$ 616.3	$ 53.0	$ 31.0
Long-term debt – interest (1)	138.0	66.5	61.4	8.4	1.7
Operating leases	23.8	1.1	3.7	3.1	15.9
Asset retirement obligations (2)	424.5	56.4	83.1	82.4	202.6
Other liabilities and commitments (3)	86.8	9.1	14.3	12.1	51.3
Total	$ 1,416.4	$ 176.1	$ 778.8	$ 159.0	$ 302.5

(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, 2021 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, 2021 and fees related to letters of credit were estimated at the rate incurred on December 31, 2021.
(b) Interest payments on the Senior Second Lien Notes were calculated per the terms of the notes;
(c) Interest payments on the Term Loan were calculated at the 7% 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, 2021 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, 2021, we had approximately $401.8 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. Included are 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, operating costs and 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

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do associated costs. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and the value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. We anticipate business costs will vary in accordance with commodity prices for oil and natural gas, and the associated increase or decrease in demand for services related to production and exploration. 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 in the United States. 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 2021, 2020 or 2019.

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 our 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 our financial position, results of operations and cash flows. We record adjustments to reflect actual taxes paid in the period we complete our tax returns.

We account 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, we recognize interest and penalties related to uncertain tax positions in income tax expense. The final settlement of these tax positions may occur several years after the tax return is filed and may result in significant adjustments depending on the outcome of these settlements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

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 2021 and assuming no other items had changed, our revenue would have decreased by approximately $65 million in 2021. If costs and expenses of operating our properties had increased by 10% in 2021, our income before income tax would have decreased by approximately $24 million in 2021. 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 year ended December 31, 2021, our average realized oil price after the effect of derivatives increased 23.5% to $55.50 per Bbl from $44.93 per Bbl during the year-ended December 31, 2020. Our average natural gas price realizations after the effect of derivatives increased 46.0% during the year ended December 31, 2021 to $2.92 per Mcf from $2.00 per Mcf during the year-ended December 31, 2020.

Interest rate risk. As of December 31, 2021, 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 London Interbank Offered Rate and the current margin is 6.0% per annum. We did not have any derivative contracts related to interest rates as of December 31, 2021.

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, 2021 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, 2021 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

The Shareholders and 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, 2021, 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, 2021, 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, 2021 and 2020, the related consolidated statements of operations, changes in shareholders' deficit, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes and our report dated March 9, 2022 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 9, 2022

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, 2021 and 2020, the related consolidated statements of operations, changes in shareholders' deficit, and cash flows for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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, 2022 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, 2021, the net book value of the Company's oil and natural gas properties was $665 million, and depreciation, depletion and amortization ("DD&A") expense was $90 million for the year then ended. As discussed in Note 1, under the full-cost method of accounting, DD&A is recorded based on the units-of-production method. 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 estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. Significant judgment is required by the independent petroleum engineers in evaluating geological

	and engineering data used to estimate oil and natural gas reserves. Estimating reserves also requires the selection of inputs, including oil and natural gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and natural gas reserves, management used independent petroleum engineers to prepare the oil and natural gas reserve estimates as of December 31, 2021. Auditing the Company's DD&A 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 over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved oil and natural gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent petroleum engineers used to prepare the oil and natural gas reserve estimates. In addition, in assessing whether we can use the work of the independent petroleum engineers we evaluated 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 and we identified and evaluated corroborative and contrary evidence. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved oil and natural gas reserve amounts used to the Company's reserve report.
	Accounting for Asset Retirement Obligation
Description of the Matter	At December 31, 2021, the asset retirement obligation (ARO) balance totaled $424 million. As further described in Notes 1 and 7, 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 9, 2022

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

	December 31, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 245,799	$ 43,726
Restricted cash	4,417	—
Receivables:		
Oil and natural gas sales	54,919	38,830
Joint interest, net	9,745	10,840
Total receivables	64,664	49,670
Prepaid expenses and other assets (Note 1)	43,379	13,832
Total current assets	358,259	107,228
Oil and natural gas properties and other, net (Note 1)	665,252	686,878
Restricted deposits for asset retirement obligations	16,019	29,675
Deferred income taxes	102,505	94,331
Other assets (Note 1)	51,172	22,470
Total assets	$ 1,193,207	$ 940,582
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$ 67,409	$ 41,304
Undistributed oil and natural gas proceeds	36,243	19,167
Advances from joint interest partners	15,072	7,308
Asset retirement obligations	56,419	17,188
Accrued liabilities (Note 1)	106,140	29,880
Current portion of long-term debt	42,960	—
Income tax payable	133	153
Total current liabilities	324,376	115,000
Long-term debt (Note 2)		
Principal	700,359	632,460
Unamortized debt issuance costs	(12,421)	(7,174)
Long-term debt, net	687,938	625,286
Asset retirement obligations, less current portion	368,076	375,516
Other liabilities (Note 1)	55,389	32,938
Deferred income taxes	113	128
Commitments and contingencies (Note 18)	4,495	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000 shares authorized; none issued at December 31, 2021 and December 31, 2020	—	—
Common stock, $0.00001 par value; 200,000 shares authorized; 145,732 issued and 142,863 outstanding at December 31, 2021; 145,174 issued and 142,305 outstanding at December 31, 2020	1	1
Additional paid-in capital	552,923	550,339
Retained deficit	(775,937)	(734,459)
Treasury stock, at cost; 2,869 shares at December 31, 2021 and December 31, 2020	(24,167)	(24,167)
Total shareholders' deficit	(247,180)	(208,286)
Total liabilities and shareholders' deficit	$ 1,193,207	$ 940,582

See accompanying notes.

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

	Year Ended December 31,		
	2021	2020	2019
Revenues:			
Oil	$ 329,557	$ 216,419	$ 399,790
NGLs	44,343	19,101	22,373
Natural gas	173,749	99,300	106,347
Other	10,361	11,814	6,386
Total revenues	558,010	346,634	534,896
Operating expenses:			
Lease operating expenses	174,582	162,857	184,281
Production taxes	10,074	4,918	2,524
Gathering and transportation	17,845	16,029	25,950
Depreciation, depletion, and amortization	90,522	97,763	129,038
Asset retirement obligations accretion	22,925	22,521	19,460
General and administrative expenses	52,400	41,745	55,107
Total operating expenses	368,348	345,833	416,360
Operating income (loss)	189,662	801	118,536
Interest expense, net	70,049	61,463	59,569
Derivative loss (gain)	175,313	(23,808)	59,887
Gain on debt transactions	—	(47,469)	—
Other (income) expense, net	(6,165)	2,978	188
(Loss) income before income taxes	(49,535)	7,637	(1,108)
Income tax benefit	(8,057)	(30,153)	(75,194)
Net (loss) income	$ (41,478)	$ 37,790	$ 74,086
Net (loss) income per common share:			
Basic	$ (0.29)	$ 0.26	$ 0.52
Diluted	(0.29)	0.26	0.52
Weighted average common shares outstanding			
Basic	142,271	141,622	140,583
Diluted	142,271	143,277	143,724

See accompanying notes.

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

	Common Stock Outstanding		Additional Paid-In	Retained	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	Deficit	Shares	Value	Deficit
Balances at December 31, 2018	140,644	$ 1	$ 545,705	$ (846,335)	2,869	$ (24,167)	$ (324,796)
Share-based compensation	—	—	3,690	—	—	—	3,690
Stock issued	1,025	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(2,345)	—	—	—	(2,345)
Net income	—	—	—	74,086	—	—	74,086
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 income	—	—	—	(41,478)	—	—	(41,478)
Balances at December 31, 2021	142,863	$ 1	$ 552,923	$ (775,937)	2,869	$ (24,167)	$ (247,180)

See accompanying notes.

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

	Year Ended December 31,		
	2021	**2020**	**2019**
Operating activities:			
Net (loss) income	$ (41,478)	$ 37,790	$ 74,086
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	113,447	120,284	148,498
Amortization of debt items and other items	6,555	6,834	5,514
Share-based compensation	3,364	3,959	3,690
Derivative loss (gain)	175,313	(23,808)	59,887
Derivative cash (payments) receipts, net	(81,298)	45,196	22,064
Derivative cash premium payments	(40,484)	—	(8,123)
Gain on debt transactions	—	(47,469)	—
Deferred income taxes	(8,189)	(30,287)	(64,102)
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(16,089)	18,537	(9,563)
Joint interest receivables	1,095	8,561	(4,766)
Prepaid expenses and other assets	(5,103)	9,563	52,214
Income tax	(20)	2,014	(9,346)
Asset retirement obligation settlements	(27,309)	(3,339)	(11,443)
Cash advances from JV partners	7,765	2,028	(15,347)
Accounts payable, accrued liabilities and other	46,099	(41,354)	(11,036)
Net cash provided by operating activities	133,668	108,509	232,227
Investing activities:			
Investment in oil and natural gas properties and equipment	(32,062)	(17,632)	(137,816)
Changes in operating assets and liabilities associated with investing activities	5,277	(26,535)	12,110
Acquisition of property interests	(661)	(2,919)	(188,019)
Purchases of furniture, fixtures and other	2	(530)	(89)
Net cash used in investing activities	(27,444)	(47,616)	(313,814)
Financing activities:			
Borrowings on credit facility	—	25,000	150,000
Repayments on credit facility	(80,000)	(50,000)	(66,000)
Purchase of Senior Second Lien Notes	—	(23,930)	—
Proceeds from Term Loan	215,000	—	—
Repayments on Term Loan	(24,142)	—	—
Debt issuance costs	(9,810)	—	(939)
Other	(782)	(670)	(2,334)
Net cash provided by (used in) financing activities	100,266	(49,600)	80,727
Increase in cash and cash equivalents	206,490	11,293	(860)
Cash and cash equivalents and restricted cash, beginning of period	43,726	32,433	33,293
Cash and cash equivalents and restricted cash, end of period	$ 250,216	$ 43,726	$ 32,433

See accompanying notes

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and subsidiaries, referred to herein as “W&T,” “we,” “us,” “our,” or the “Company”, is an independent oil and natural gas producer with substantially all of its operations in the Gulf of Mexico. We are active in the exploration, development and acquisition of oil and natural gas properties. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc. (on a stand-alone basis, the “Parent Company”) and our 100% owned subsidiaries, W & T Energy VI, LLC, Aquasition LLC, and Aquasition II, LLC, and through our proportionately consolidated interest in Monza Energy, LLC (“Monza”), as described in more detail in *Note 4 – Mobile Bay Transaction*.

Basis of Presentation

Our consolidated financial statements include the accounts of W&T Offshore, Inc. and its majority-owned subsidiaries. Our interests in oil and gas joint ventures are proportionately consolidated. All significant intercompany transactions and amounts have been eliminated for all years presented. Our consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (“GAAP”) and the appropriate rules and regulations of the Securities and Exchange Commission (“SEC”).

For presentation purposes, as of December 31, 2021, *Derivative loss (gain)* has been moved out of “Operating income (loss)” on the Consolidated Statement of Operations. Such reclassification had no effect on our 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.

Accounting Standard Updates Effective January 1, 2021

Simplifying the Accounting for Income Taxes. In December 2019, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes* ("ASU 2019-12"). ASU 2019-12 simplifies the accounting for income taxes by removing certain exceptions to the general principles in Topic 740 and by clarifying and amending existing guidance. ASU 2019-12 is effective for annual and interim financial statement periods beginning after December 15, 2020. Adoption of the amendment did not have a material impact on our financial statements or disclosures.

Cash Equivalents

We consider 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 issued by certain commercial bank lenders under the Credit Agreement prior to the Ninth Amendment. See *Note 2 –Debt* for additional information.

Revenue Recognition

We recognize revenue from the sale of crude oil, NGLs, and natural gas when our performance obligations are satisfied. Our contracts with customers are primarily short-term (less than 12 months). Our responsibilities to deliver a unit of crude oil, NGL, and natural gas under these contracts represent separate, distinct performance obligations. These performance obligations are satisfied at the point in time control of each unit is transferred to the customer. Pricing is primarily determined utilizing a particular pricing or market index, plus or minus adjustments reflecting quality or location differentials.

We record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which we have taken less than our ownership share of production. At December 31, 2021 and 2020, $3.5 million and $3.5 million, respectively, were included in current liabilities related to natural gas imbalances.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies and large commodity trading companies. The majority of our production is sold utilizing month-to-month contracts that are based on bid prices. We attempt to minimize our credit risk exposure to purchasers of our oil and natural gas, 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 from whom we derived 10% or more of our receipts from sales of crude oil, NGLs and natural gas:

	Year Ended December 31,		
	2021	2020	2019
Customer			
BP Products North America	34 %	39 %	40 %
Chevron - Texaco	14 %	**	**
Mercuria Energy America Inc.	**	10 %	**
Shell Trading (US) Co./ Shell Energy N.A.	**	**	11 %
Vitol Inc.	**	**	12 %
Williams Field Services	11 %	13 %	**

** Less than 10%

We believe that the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and natural gas production as 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

Our accounts receivables are recorded at their historical cost, less an allowance for credit losses. The carrying value approximates fair value because of the short-term nature of such accounts. In addition to receivables from sales of our production to our customers, we also have receivables from joint interest owners on properties we operate. In certain arrangements, we have the ability to withhold future revenue disbursements to recover amounts due us from the joint interest partners. A loss methodology is used to develop the allowance for credit losses on material receivables to estimate the net amount to be collected. The loss methodology uses historical data, current market conditions and forecasts of future economic conditions. The following table describes the balance and changes to the allowance for credit losses (in thousands):

	2021	2020	2019
Allowance for credit losses, beginning of period	$ 9,123	$ 9,898	$ 9,692
Additional provisions for the year	2,192	417	206
Uncollectible accounts written off or collected	(1,269)	(1,192)	—
Allowance for credit losses, end of period	$ 10,046	$ 9,123	$ 9,898

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,	
	2021	2020
Derivatives – current [1]	$ 21,086	$ 2,752
Unamortized insurance/bond premiums	5,400	4,717
Prepaid deposits related to royalties	8,441	4,473
Prepayment to vendors	4,522	1,429
Prepayments to joint interest partners	2,808	402
Debt issue costs	1,065	—
Other	57	59
Prepaid expenses and other assets	$ 43,379	$ 13,832

(1) Includes both open and closed contracts that have not yet settled and prepaid premiums paid for purchased put and call options.

Oil and Natural Gas Properties and Other, Net

We use the full-cost method of accounting for oil and natural gas properties and equipment, which are recorded at cost. 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 ("ARO"), 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 include costs of unproved properties. The cost of unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as we have made an evaluation that impairment has occurred. As of December 31, 2021 and 2020, there were no unproved properties included in the *Oil and natural gas properties and other, net* balance. 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,	
	2021	2020
Oil and natural gas properties and equipment	$ 8,636,408	$ 8,567,509
Furniture, fixtures and other	20,844	20,847
Total property and equipment	8,657,252	8,588,356
Less: Accumulated depreciation, depletion, amortization and impairment	7,992,000	7,901,478
Oil and natural gas properties and other, net	$ 665,252	$ 686,878

Ceiling Test Write-Down

Under the full-cost method of accounting, we are required to perform a "ceiling test" calculation quarterly, which determines a limit on the book value of our 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.

We did not record a ceiling test write-down during 2021, 2020 or 2019. If average crude oil and natural gas prices decrease below average pricing during 2021, we may incur ceiling test write-downs during 2022 or in future periods.

Asset Retirement Obligations

We are required to record a separate liability for the present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet. We have significant obligations to plug and abandon well bores, remove our 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. Estimating such costs requires us to make judgments on both the costs and the timing of ARO. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. See *Note 7 – Asset Retirement Obligations* for additional information.

Oil and Natural Gas Reserve Information

We use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period when estimating quantities of proved reserves. Similarly, the prices used to calculate the standardized measure of discounted future cash flows and prices used in the ceiling test for impairment are the 12-month average commodity prices. 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 about our proved reserves.

Derivative Financial Instruments

We have exposure related to commodity prices and have used various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas. We do not enter into derivative instruments for speculative trading purposes. We entered into commodity derivatives contracts during 2021, 2020 and 2019, and as of December 31, 2021, we had open commodity derivative instruments. When we have outstanding borrowings on our revolving bank credit facility, we may use various derivative financial instruments to manage our exposure to interest rate risk from floating interest rates. During 2021, 2020 and 2019, we did not enter into any derivative instruments related to interest rates.

Derivative instruments are recorded on the balance sheet as an asset or a liability at fair value. We have elected not to designate our derivatives instruments as hedging instruments, therefore, all changes in fair value are recognized in earnings. See *Note 10 – Derivative Financial Instruments* for additional information about our derivative financial instruments.

Fair Value of Financial Instruments

We include fair value information in the notes to our consolidated financial statements when the fair value of our financial instruments is different from the book value or it is required by applicable guidance. We believe that the book value of our cash and cash equivalents, receivables, accounts payable and accrued liabilities materially approximates fair value due to the short-term nature and the terms of these instruments. We believe that the book value of our restricted deposits approximates fair value as deposits are in cash or short-term investments.

Income Taxes

We use the liability method of accounting for income taxes in accordance with the *Income Taxes* topic of the Accounting Standard Codification. Under this method, deferred tax assets and liabilities are 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. 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. We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. We classify interest and penalties related to uncertain tax positions 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, 2021		December 31, 2020	
Right-of-Use assets (Note 8)	$	10,602	$	11,509
Unamortized debt issuance costs		—		2,094
Investment in White Cap, LLC		2,533		2,699
Unamortized brokerage fee for Monza		—		626
Proportional consolidation of Monza's other assets (Note 5)		2,511		1,782
Derivatives (1)		34,435		2,762
Other		1,091		998
Total other assets (long-term)	$	51,172	$	22,470

(1) Includes open contracts and prepaid premiums paid for purchased put and call options

Accrued Liabilities

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

	December 31, 2021		December 31, 2020	
Accrued interest	$	10,154	$	10,389
Accrued salaries/payroll taxes/benefits		9,617		4,009
Litigation accruals		646		436
Lease liability		1,115		394
Derivatives (1)		81,456		13,620
Other		3,152		1,032
Total accrued liabilities	$	106,140	$	29,880

(1) Includes both open and closed contracts.

Paycheck Protection Program ("PPP")

On April 15, 2020, the Company received $8.4 million under the U.S. Small Business Administration ("SBA") PPP. As there is no definitive guidance under U.S. GAAP, we have 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.

The Company submitted an application to the SBA on August 20, 2020, requesting that the PPP funds received be applied to specific covered and non-covered payroll costs. On June 11, 2021, we received notification that the SBA accepted our application and approved full forgiveness of our PPP.

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. Debt issuance costs associated with all other debt are deferred and amortized over the scheduled maturity of the debt utilizing the effective interest method. Unamortized debt issuance costs associated with our Credit Agreement is reported within *Prepaid expenses and other assets* and unamortized debt issuance costs associated with our other debt instruments are reported as a reduction in *Long-term debt, net* in the Consolidated Balance Sheets. See *Note 2 –Debt* for additional information.

Gain on Debt Transactions

During 2020, we acquired $72.5 million in principal of our outstanding Senior Second Lien Notes for $23.9 million and recorded a non-cash gain on purchase of debt of $47.5 million. During 2018, the refinancing of our capital structure resulted in a gain of $47.1 million as a result of writing off the carrying value adjustments related to the debt issued in 2016, partially offset by premiums paid to repurchase and retire, repay or redeem all of our prior debt instruments. See *Note 2 – Debt* for additional information.

Other Liabilities (long-term)

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

	December 31,	
	2021	2020
Dispute related to royalty deductions	$ 5,177	$ 5,467
Derivatives	37,989	4,384
Lease liability (Note 8)	11,227	11,360
Black Elk escrow	—	11,103
Other	996	624
Total other liabilities (long-term)	$ 55,389	$ 32,938

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. We recognize share-based compensation expense on a straight line basis 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 estimated 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 ("CARES 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 which is included as a credit to *General and administrative expenses* in the Consolidated Statement of Operations.

Other Expense (Income), Net

For 2021, the amount primarily consists of other 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. For 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* for additional information regarding the release of the Black Elk Escrow restrictions. For 2019, the amount consists primarily of federal royalty obligation reductions claimed in the current year related to capital deductions from prior periods, and partially offset by expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program.

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.

2. Debt

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

	December 31, 2021	December 31, 2020
Term Loan:		
Principal	$ 190,859	$ —
Unamortized debt issuance costs	(7,545)	—
Total Term Loan	183,314	—
Credit Agreement borrowings:	—	80,000
Senior Second Lien Notes:		
Principal	552,460	552,460
Unamortized debt issuance costs	(4,876)	(7,174)
Total Senior Second Lien Notes	547,584	545,286
Less current portion	(42,960)	—
Total long-term debt, net	$ 687,938	$ 625,286

Aggregate annual maturities of amounts recorded as of December 31, 2021 are as follows (in millions):

2022	$ 43.0
2023	586.2
2024	30.1
2025	27.6
2026	25.4
Thereafter	31.0
Total	$ 743.3

Current portion of Long-Term Debt

As of December 31, 2021, the current portion of long-term debt of $43.0 represented principal payments due within one year of the Term Loan (defined below).

Term Loan (Subsidiary Credit Agreement)

On May 19, 2021, Aquasition LLC and Aquasition II LLC, both Delaware limited liability companies and indirect, wholly-owned subsidiaries of W&T Offshore, Inc., entered into a credit agreement (the "Subsidiary Credit Agreement") providing for a term loan in an aggregate principal amount equal to $215.0 million (the "Term Loan"). The Term Loan requires quarterly amortization payments commencing September 30, 2021. The Term Loan bears interest at a fixed rate of 7% per annum and will mature on May 19, 2028. 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).

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”). 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 (defined below), with the majority of the proceeds to W&T expected to be used for general corporate purposes, including oil and gas acquisitions, development activities, and other opportunities to grow the Company’s broader asset base. We refer to the transactions contemplated by the Subsidiary Credit Agreement, including the assignment of the Mobile Bay Properties to A-I LLC and the assignment of the Midstream Assets to A-II LLC as the “Mobile Bay Transaction”.

For information about Mobile Bay Transaction refer to *Note 4 – Mobile Bay Transaction*.

9.75% Senior Second Lien Notes Due 2023

On October 18, 2018, we issued $625.0 million of 9.75% Senior Second Lien Notes due 2023 (the “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 Senior Second Lien Notes (the “Indenture”), entered into by and among the Company, the Guarantors, and Wilmington Trust, National Association, as trustee (the “Trustee”). The estimated annual effective interest rate on the Senior Second Lien Notes was 10.3%, which includes debt issuance costs. Interest on the Senior Second Lien Notes is payable in arrears on May 1 and November 1 of each year.

During the year ended December 31, 2020, we acquired $72.5 million in principal of our outstanding 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.

As of November 1, 2020, we may redeem the Senior Second Lien Notes, in whole or in part, at redemption prices (expressed as percentages of the principal amount thereof) equal to 104.875% for the 12-month period beginning November 1, 2020, 102.438% for the 12-month period beginning November 1, 2021, and 100.0% on November 1, 2022 and thereafter, plus accrued and unpaid interest, if any, to the redemption date. The Senior Second Lien Notes are guaranteed by W&T Energy VI and W & T Energy VII, LLC (together, the “Guarantor Subsidiaries”). If we experience certain change of control events, we will be required to offer to repurchase the notes at 101.0% of the principal amount, plus accrued and unpaid interest, if any, to the repurchase date.

The Senior Second Lien Notes are secured by a second-priority lien on all of our assets that are secured under the Sixth Amended and Restated Credit Agreement (as amended, the “Credit Agreement”). The Senior Second Lien Notes contain covenants that limit or prohibit our ability and the ability of certain of our 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 restricted 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 unrestricted subsidiaries that would not be restricted by the covenants of the Indenture. These covenants are subject to 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 Senior Second Lien Notes an investment grade rating and no default exists with respect to the Senior Second Lien Notes.

Credit Agreement

On November 2, 2021, the Company entered into the Eighth Amendment to the Credit Agreement (the "Eighth Amendment") which effectively terminated the Company's reserve based lending relationship with commercial bank lenders who have traditionally provided its secured revolving credit facility. The Company has not had any borrowings under the Credit Agreement since the closing of the Mobile Bay Transaction in May 2021. As of November 2, 2021, the Company has cash collateralized each of the outstanding letters of credit in the aggregate amount of approximately $4.4 million. Alter Domus (US) LLC was appointed to replace Toronto Dominion (Texas) LLC as administrative agent under the Credit Agreement.

On November 2, 2021, the Company also entered into the Ninth Amendment to the Credit Agreement (the "Ninth Amendment"), which establishes a short-term $100.0 million first priority lien secured revolving facility with borrowings limited to a borrowing base of $50.0 million (the "Calculus Lending facility") 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. A committee of the independent members of the Board of Directors reviewed and approved the amendments given the CEO's affiliation with Calculus Lending, LLC. As a result of the Eighth Amendment and Ninth Amendment and related assignments and agreements, the key terms and covenants associated with the Calculus Lending facility under the Credit Agreement as of December 31, 2021 are as follows:

- The revised borrowing base is $50.0 million.
- The Calculus Lending facility commitment will expire and final maturity of any and all outstanding loans is April 30, 2022. Outstanding borrowings will accrue interest at LIBOR 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 outstanding under the Calculus Lending facility 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 ending 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 ending 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 Company and its restricted subsidiaries' 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 ending 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.

As consideration for its commitment as sole lender and consistent with customary non-commercial bank lending practice, Calculus was paid certain market-based fees in connection with its commitment.

Availability under the Credit Agreement is subject to redetermination of our borrowing base that may be requested at the discretion of either the lender or the Company. The borrowing base is calculated by our lender based on their evaluation of our proved reserves and their own internal criteria. Any redetermination by our lender to change our 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 our oil and natural gas properties and personal property, excluding those assets of the Subsidiary Borrowers, which liens were released in the Mobile Bay Transaction (as described in *Note 4 – Mobile Bay Transaction*). Subsequent to December 31, 2021, the Company entered into the Tenth Amendment to Sixth Amended and Restated Credit Agreement and Extension Agreement, which extended the maturity date and Lender commitment to January 3, 2023 (see *Note 20 – Subsequent Events* for additional information).

Borrowings outstanding under the Credit Agreement are reported in the table above. The estimated annual effective interest rate on borrowings, exclusive of debt issuance costs, commitment fees and other fees was 3.2%. Separately, as of December 31, 2021 and 2020, we had $4.4 million, outstanding in letters of credit which have been cash collateralized as of December 31, 2021.

As of December 31, 2021 and for all presented measurement periods, we were in compliance with all applicable covenants of the Credit Agreement and Senior Second Lien Notes.

For information about fair value measurements of our long term debt, refer to *Note 3 – Fair Value Measurements*.

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 our expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

Derivative Financial Instruments

As of December 31, 2021 and 2020, the carrying value of our open derivative contracts equaled the estimated fair value. We measure the fair value of our open 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 our open 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. Our open derivative financial instruments are reported in the Consolidated Balance Sheets using fair value. See *Note 10 – Derivative Financial Instruments*, for additional information on our derivative financial instruments.

The following table presents the fair value of our open derivative financial instruments (in thousands):

	December 31,	
	2021	2020
Assets:		
Derivative instruments - open contracts, current	$ 19,215	$ 2,705
Derivative instruments - open contracts, long-term	34,435	2,762
Liabilities:		
Derivative instruments - open contracts, current	73,190	13,291
Derivative instruments - open contracts, long-term	37,989	4,384

Debt

The fair value of the Term Loan was measured using a discounted cash flows model and current market rates. The net value of our debt under the Credit Agreement approximates fair value because the interest rates are variable and reflective of current market rates. The fair value of our Senior Second Lien Notes was measured using quoted prices, although the market is not a highly liquid market. The fair value of our debt was classified as Level 2 within the valuation hierarchy. See *Note 2 – Debt* for additional information on our debt.

The following table presents the net value and fair value of our long-term debt (in thousands):

	December 31, 2021		December 31, 2020	
	Net Value	Fair Value	Net Value	Fair Value
Liabilities:				
Term Loan	$ 183,314	$ 190,579	$ —	$ —
Credit Agreement	—	—	80,000	80,000
Senior Second Lien Notes	547,584	527,715	545,286	393,352
Total	730,898	718,294	625,286	473,352

4. Mobile Bay Transaction

On May 19, 2021, the Company's wholly-owned special purpose vehicles, A-I LLC and A-II LLC or 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 Mobile Bay 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 will not be available to satisfy the debt or contractual obligations of any entities other than the Subsidiary Borrowers, including debt securities or other contractual obligations of W&T Offshore, Inc., and the Subsidiary Borrowers do not bear any liability for the indebtedness or other contractual obligations of any entity other than the Subsidiary Borrowers, and vice versa.

As of December 31, 2021, in the Consolidated Balance Sheet, we recorded $38.9 million in *Cash and cash equivalents,* $272.7 million, in *Oil and natural gas properties and other, net*, $43.0 million in *Current portion of long-term debt,* $54.5 million in *Asset retirement obligations*, and $140.4 million in *Long-term debt, net* related to the consolidation of the Subsidiary Borrowers and the subsidiary that owns the equity of the Subsidiary Borrowers. For 2021, in the Consolidated Statement of Operations, we recorded $119.6 million in *Total revenues*, $32.7 million in *Operating costs and expenses*, $104.5 million in *Derivative loss*, and $9.8 million in *Interest expense, net* related to the consolidation of the operations of the Subsidiary Borrowers and the subsidiary that owns the equity of the Subsidiary Borrowers.

5. Joint Venture Drilling Program

In March 2018, W&T and two other initial members formed and initially funded Monza, which jointly participates with us 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 we initially receive an aggregate of 30.0% of the revenues less expenses, through both our direct ownership of our working interest in the projects and our indirect interest through our 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. W&T is the operator for seven of the nine wells completed through December 31, 2021.

The members of Monza are made up of third-party investors, W&T and an entity owned and controlled by Mr. Tracy W. Krohn, our Chairman and Chief Executive Officer. The Krohn entity 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, 2021, nine wells have been completed of which five were producing as of December 31, 2021. W&T is the operator for seven of the nine wells completed through December 31, 2021.

Through December 31, 2021, members of Monza made partner capital contributions, including our contributions of working interest in the drilling projects, to Monza totaling $302.4 million and received cash distributions totaling $90.1 million. Our net contribution to Monza, reduced by distributions received, as of December 31, 2021 was $49.0 million. W&T is obligated to fund certain cost overruns to the extent they occur, subject to certain exceptions, for the Joint Venture Drilling Program wells above budgeted and contingency amounts, of which the total exposure cannot be estimated at this time.

Consolidation and Carrying Amounts

Our interest in Monza is considered to be a variable interest that we account for using proportional consolidation. Through December 31, 2021, there have been no events or changes that would cause a redetermination of the variable interest status. We do not fully consolidate Monza because we are not considered the primary beneficiary. As of December 31, 2021, in the Consolidated Balance Sheet, we recorded $3.5 million, net, in *Oil and natural gas properties and other, net*, $2.5 million in *Other assets,* $0.3 million in ARO and $4.6 million, net, increase in working capital in connection with our proportional interest in Monza's assets and liabilities. As of December 31, 2020, in the Consolidated Balance Sheet, we recorded $9.9 million, net, in *Oil and natural gas properties and other, net*, $1.8 million in *Other assets,* $0.2 million in ARO and $1.3 million, net, increase in working capital in connection with our proportional interest in Monza's assets and liabilities. Additionally, during 2021 and 2020, we called 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, 2021 and 2020 were $14.8 million and $7.3 million, respectively, which are included in the Consolidated Balance Sheet in *Advances from joint interest partners*. For 2021, in the Consolidated Statement of Operations, we recorded $12.7 million in *Total revenues,* $10.0 million in *Operating costs and expenses*, and $2.1 million in *Derivative loss* in connection with our proportional interest in Monza's operations. For 2020, in the Consolidated Statement of Operations, we recorded $8.4 million in *Total revenues*, $11.4 million in *Operating costs and expenses*, and $0.8 million in *Derivative loss* in connection with our proportional interest in Monza's operations.

6. Acquisitions and Divestitures

Mobile Bay Properties

In August 2019, we completed the purchase of Exxon Mobil Corporation's ('Exxon') interests in and operatorship of oil and gas producing properties in the eastern region of the Gulf of Mexico offshore Alabama and related onshore and offshore facilities and pipelines, (the 'Mobile Bay Properties'). After taking into account customary closing adjustments and an effective date of January 1, 2019, cash consideration paid by us was $169.8 million which includes expenses related to the acquisition. We also assumed the related ARO and certain other obligations associated with these assets. The acquisition was funded from cash on hand and borrowings of $150.0 million under the Credit Agreement, which were previously undrawn. We determined that the assets acquired did not meet the definition of a business; therefore, the transaction was accounted for as an asset acquisition. The following table presents the purchase price allocation (in thousands):

	2019
Oil and natural gas properties and other, net - at cost:	$ 192,373
Other assets	4,838
Current liabilities	1,559
Asset retirement obligations	21,684
Other liabilities	4,132

During 2020, we completed the purchase of the remaining interest in two federal Mobile Bay fields from Chevron U.S.A. Inc. ('Chevron'). After taking into account customary closing adjustments and an effective date of January 1, 2020, cash consideration paid by us was $2.2 million which includes expenses related to the acquisition.

Magnolia Field

In December 2019, we completed the purchase of ConocoPhillips Company's ('Conoco') interests in and operatorship of oil and gas producing properties at Garden Banks blocks 783 and 784 (the 'Magnolia Field'). After taking into account customary closing adjustments and an effective date of October 1, 2019, cash consideration was $15.9 million which includes cash expenses related to the acquisition. We also assumed the related ARO. The acquisition was funded from cash on hand. We determined that the assets acquired did not meet the definition of a business; therefore, the transaction was accounted for as an asset acquisition. The following table presents the purchase price allocation (in thousands):

	2019
Oil and natural gas properties and other, net - at cost:	$ 23,791
Asset retirement obligations	7,842

During 2020, we completed the purchase of the remaining interest in the Magnolia field from Marubeni Oil & Gas (USA) ('Marubeni'). After taking into account customary closing adjustments and an effective date of October 1, 2019, cash consideration paid by us was $1.5 million which includes expenses related to the acquisition.

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 our 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 table is a reconciliation of our ARO (in thousands):

	Year Ended December 31,	
	2021	2020
Asset retirement obligations, beginning of period	$ 392,704	$ 355,594
Liabilities settled	(27,309)	(3,339)
Accretion of discount	22,925	22,521
Liabilities incurred and assumed through acquisition	454	4,860
Revisions of estimated liabilities (1)	35,721	13,068
Asset retirement obligations, end of period	424,495	392,704
Less current portion	(56,419)	(17,188)
Long-term	$ 368,076	$ 375,516

(1) Revisions in 2021 and 2020 were due to changes in scope, weather impact, revisions to actual expenses versus estimates and revisions related to non-operated properties.

8. Leases

Our lease contracts consist 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 our 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. All of these lease contracts are operating leases.

During 2020, we terminated the existing office lease and executed a new lease on separate office space. The term of the previous office lease ended in December 2020. The term of the new office lease extends to February 2032 and has the option to renew for up to another 10 years. During 2019, various pipeline rights-of-way contracts and a land lease were acquired, assumed, renewed or otherwise entered into, primarily in conjunction with acquiring the Mobile Bay Properties. The term of each pipeline right-of-way contract is 10 years with various effective dates, and each has an option to renew for up to another ten years. It is expected renewals beyond 10 years can be obtained as renewals were granted to the previous lessees. The land lease has an option to renew every five years extending to 2085. The expected term of the rights-of way and land leases was estimated to approximate the life of the related reserves. We recorded ROU assets and lease liabilities using a discount rate of 9.75% for the office lease and 10.75% for the other leases due to their longer expected term.

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. 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, 2021	December 31, 2020
Operating lease cost, excluding short-term leases	$ 1,743	$ 3,060
Short-term lease cost [1]	5,926	1,633
Total lease cost	$ 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 were recorded within *Oil and natural gas properties and other, net*, on the Consolidated Balance Sheet.

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, 2021	December 31, 2020
ROU assets	$ 10,602	$ 11,509
Lease liability:		
Accrued liabilities	$ 1,115	$ 394
Other liabilities	11,227	11,360
Total lease liability	$ 12,342	$ 11,754

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

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

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

	December 31, 2021	December 31, 2020
Operating cash outflow from operating leases	$ 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, 2021 are as follows (in thousands):

2022	$ 1,134
2023	1,625
2024	2,023
2025	1,512
2026	1,542
Thereafter	15,919
Total lease payments	23,755
Present value adjustment	(11,413)
Total	$ 12,342

9. Restricted Deposits for ARO

Restricted deposits as of December 31, 2021 and 2020 consisted of funds escrowed for collateral related to the future plugging and abandonment obligations of certain oil and natural gas properties.

Pursuant to the Purchase and Sale Agreement with Total E&P USA Inc. ("Total E&P"), security for future plugging and abandonment of certain oil and natural gas properties is required either through surety bonds or payments to an escrow account or a combination thereof. Monthly payments are made to an escrow account and these funds are returned to us once verification is made that the security amount requirements have been met. See *Note 16 - Commitments* for potential future security requirements.

During the year ended December 31, 2020, W&T received $13.9 million of cash as a restricted deposit to be used exclusively for payment of certain asset retirement obligations related to properties sold by W&T to Black Elk Energy Offshore Operations, LLC ("Black Elk") in October 2009 in connection with the liquidation of Black Elk under Chapter *11* of the U.S. Bankruptcy Code. The cash was retained in an escrow account and recorded within *Restricted Deposits for asset retirement obligations* on the Consolidated Balance Sheet as of December 31, 2020*.* As of December 31, 2020, $11.1 million was recorded in *Other liabilities* as our estimate of the additional asset retirement obligations to be funded from the restricted deposit account. On December 29, 2021, the United States Bankruptcy Court for the Southern District of Texas sent the Company notice that we are able to retain the remaining funds and that those funds were no longer subject to any restrictions, effectively releasing the cash from escrow. Accordingly, we removed the remaining liability of $11.1 million and transferred the related cash previously retained in escrow to cash. We recorded the $11.1 million in *Other (income) expense* during the year ended December 31, 2021.

10. Derivative Financial Instruments

During 2021, 2020 and 2019, we entered into commodity contracts for crude oil and natural gas which related to a portion of our expected production for the time frames covered by the contracts. The crude oil contracts were based on West Texas Intermediate ("WTI") crude oil prices as quoted off the New York Mercantile Exchange ("NYMEX"). The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX. The open contracts as of December 31, 2021 are presented in the following tables:

Period	Instrument Type	Average Daily Volumes	Total Volumes	Weighted Strike Price	Weighted Put Price	Weighted Call Price
Crude Oil - WTI (NYMEX)		*(Bbls)*[1]	*(Bbls)*[1]	*($/Bbls)*[1]	*($/Bbls)*[1]	*($/Bbls)*[1]
Jan 2022 - Nov 2022	swaps	2,525	843,256	$ 49.99	$ —	$ —
Jan 2022 - Nov 2022	collars	2,428	811,096	$ —	$ 41.71	$ 58.91
Natural Gas - Henry Hub (NYMEX)		*(MMbtu)*[2]	*(MMbtu)*[2]	*($/MMbtu)*[2]	*($/MMbtu)*[2]	*($/MMbtu)*[2]
Jan 2022 - Dec 2022	calls	116,853	42,651,402	$ —	$ —	$ 3.93
Jan 2023 - Dec 2023	calls	70,000	25,550,000	$ —	$ —	$ 3.50
Jan 2024 - Dec 2024	calls	65,000	23,790,000	$ —	$ —	$ 3.50
Jan 2025 - Mar 2025	calls	62,000	5,580,000	$ —	$ —	$ 3.50
Jan 2022 - Dec 2022	collars	47,370	17,290,000	$ —	$ 1.89	$ 3.17
Jan 2022 - Nov 2022	swaps	17,160	5,731,485	$ 2.60	$ —	$ —
Jan 2022 - Dec 2022 [3]	swaps	78,904	28,800,000	$ 2.69	$ —	$ —
Jan 2023 - Dec 2023 [3]	swaps	72,329	26,400,000	$ 2.48	$ —	$ —
Jan 2024 - Dec 2024 [3]	swaps	65,574	24,000,000	$ 2.46	$ —	$ —
Jan 2025 - Mar 2025 [3]	swaps	63,333	5,700,000	$ 2.72	$ —	$ —
Apr 2025 - Dec 2025 [3]	puts	62,182	17,100,000	$ —	$ 2.27	$ —
Jan 2026 - Dec 2026 [3]	puts	55,890	20,400,000	$ —	$ 2.35	$ —
Jan 2027 - Dec 2027 [3]	puts	52,603	19,200,000	$ —	$ 2.37	$ —
Jan 2028 - Apr 2028 [3]	puts	49,587	6,000,000	$ —	$ 2.50	$ —

(1) Bbls – Barrels

(2) MMbtu – Million British Thermal Units

(3) These contracts were entered into by the Company's wholly owned subsidiary, A-I LLC, in conjunction with the Mobile Bay Transaction (see *Note 4 – Mobile Bay Transaction).*

The following amounts were recorded in the Consolidated Balance Sheets in the categories presented and include the fair value of open contracts as well as closed contracts that had not yet settled (in thousands):

	December 31, 2021	December 31, 2020
Prepaid expenses and other current assets	$ 21,086	$ 2,752
Other assets (long-term)	34,435	2,762
Accrued liabilities	81,456	13,620
Other liabilities (long-term)	37,989	4,384

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 our commodity derivative contracts has on the Consolidated Statements of Operations were as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Realized loss (gain)	$ 95,187	$ (33,415)	$ 884
Unrealized loss (gain)	80,126	9,607	59,003
Derivative loss (gain)	175,313	(23,808)	59,887

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,		
	2021	2020	2019
Derivative loss (gain)	$ 175,313	$ (23,808)	$ 59,887
Derivative cash (payments) receipts, net	(81,298)	45,196	22,064
Derivative cash premium payments	(40,484)	—	(8,123)

11. Share-Based Awards and Cash-Based Awards

Incentive Compensation Plan

The W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, and subsequent amendments, (the "Plan") was approved by our 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 2021 and 2019, 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, 2021, there were 9,852,351 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 2021, 2020 and 2019, 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 2021 grants. The 2021 RSUs granted are a long-term compensation component, subject to service conditions, with one-third of the award vesting each year on January 1, 2022, 2023, and 2024, respectively. The 2019 grants were subject to predetermined performance criteria applied against the applicable performance period and were also subject the satisfaction of the service conditions. Vesting of the outstanding 2019 RSUs occurred in December 2021. See the table below for anticipated vesting by year of outstanding RSU grants.

We recognize compensation cost for share-based payments to employees 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. The fair values for the RSUs granted during 2021 and 2019 were determined using the Company's closing price on the grant date. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that are expected to actually vest. 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:

	2021		2020		2019	
	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	763,688	$ 4.51	1,614,722	$ 5.73	3,355,917	$ 3.90
Granted	710,441	4.71	—	—	994,698	4.51
Vested	(731,095)	4.51	(787,203)	6.90	(1,475,373)	2.76
Forfeited	(44,569)	4.50	(63,831)	5.80	(1,260,520)	3.37
Nonvested, end of period	698,465	$ 4.71	763,688	$ 4.51	1,614,722	$ 5.73

RSUs fair value at grant date - During 2021 and 2019, the grant date fair value of RSUs granted was $3.3 million and $4.5 million, respectively. There were no RSUs granted during 2020.

RSUs fair value at vested date - The fair value of the RSUs that vested during 2021, 2020 and 2019 was $2.4 million, $2.0 million and $7.0 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, 2021, vesting is expected to occur as follows (subject to forfeitures):

	Restricted Shares
2022	232,822
2023	232,822
2024	232,821
Total	698,465

Performance Share Units ("PSUs")

As of December 31, 2021, the Company granted PSUs under the plan to certain employees. There were no PSUs granted in 2020 and 2019. 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 (2021) and service-based criteria. TSR is determined based on the change in the entity's stock price plus dividends and distributions for the applicable performance period. Subsequent to the performance period, the PSUs will continue to be subject to service-based criteria with vesting occurring on October 1, 2023.

A summary of activity related to PSUs is as follows:

	2021	
	Performance Share Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, beginning of period	—	$ —
Granted	393,073	5.56
Vested	—	—
Forfeited	(196,155)	5.57
Nonvested, end of period	196,918	5.55

We recognize compensation cost for share-based payments to employees 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. Our key assumptions in the method include the price and the expected volatility of our stock and our self-determined Peer Group companies' stock, risk free rate of return and cross-correlations between the Company and our Peer Group companies. The valuation model assumes dividends, if any, are immediately reinvested. The grant date fair value of the PSUs granted as of December 31, 2021 is $1.9 million. The following table summarizes the assumptions used to calculate the grant date fair value of the PSUs granted:

	2021 Grant Date June 28
Remaining term for performance period (in years)	0.5
Expected volatility	67.9 %
Risk-free interest rate	0.1 %

Share-Based Awards: Restricted Stock

Under the Directors Compensation Plan, shares of restricted stock ("Restricted Shares") were issued in 2021, 2020 and 2019 to the Company's non-employee directors as a component of their compensation arrangement. Vesting occurs upon completion of the specified vesting period, which was three years for the 2019 grants and one year for the 2020 and 2021 grants. 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, 2021, there were 410,742 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:

	2021		2020		2019	
	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	154,128	$ 3.64	123,180	$ 4.55	181,832	$ 3.08
Granted	62,502	3.36	109,376	2.56	46,360	6.04
Vested	(146,404)	3.51	(78,428)	2.38	(105,012)	2.67
Nonvested, end of period	70,226	$ 3.65	154,128	$ 3.64	123,180	$ 4.55

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2021 are eligible to vest in 2022.

Restricted stock fair value at grant date - The grant date fair value of restricted stock granted during 2021, 2020 and 2019 was $0.2 million, $0.3 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 2021, 2020 and 2019 was $0.5 million, $0.2 million and $0.5 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,		
	2021	2020	2019
Restricted stock units	$ 2,579	$ 3,555	$ 3,410
Performance share units	412	—	—
Restricted Shares	373	404	280
Total	$ 3,364	$ 3,959	$ 3,690

As of December 31, 2021, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $1.4 million and $0.1 million, respectively. Unrecognized compensation expense will be recognized through November 2022 for our RSUs and April 2023 for our Restricted Shares.

Cash-based Incentive Compensation

Short-term Cash-Based Incentive Compensation

There are two components of the short-term cash-based incentive award granted during as of December 31, 2021.

- The first short-term, cash-based award granted in February 2021 was discretionary and 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.

- For the second short-term, cash-based award granted in June 2021, a portion of the Company performance-based criteria and individual performance criteria were achieved. In addition, the Board of Directors approved a discretionary amount. Incentive compensation expense of $6.5 million was recognized in 2021 related to these cash-based awards. Payments are expected to be 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

The 2021 long-term, cash-based awards (“Cash Awards”) were granted in June 2021 and are subject to the same performance-based criteria as the PSUs noted above. The Company’s TSR ranking against peer companies will be evaluated for the performance period of 2021. Subsequent to the performance period, the Cash Awards will continue to be subject to service-based criteria with vesting occurring on October 1, 2023.

These Cash Awards are accounted for as liability awards and are measured at fair value each reporting date through the end of the performance period. We recognize compensation cost for long-term cash-based awards to employees over the service period from June 28, 2021 through October 1, 2023. The reporting date fair value of the awards as of December 31, 2021 was determined through the calculation of the total shareholder return of our stock against our self-determined peer group companies’ stock, using the risk-free rate of return, and an appropriate discount rate. The fair value of the awards as of December 31, 2021 is $1.0 million. As of December 31, 2021, unrecognized compensation expense related to these awards was $0.8 million. The following table summarizes the assumptions used to calculate the fair value of the outstanding long-term Cash Awards as of December 31, 2021:

Estimated performance achievement	50.8 %
Risk-free interest rate	0.7 %
Expected term for cash payment (in years)	1.8
Discount rate used to discount expected cash payment	12.5 %

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,		
	2021	2020	2019
Share-based compensation included in:			
General and administrative expenses	$ 3,364	$ 3,959	$ 3,690
Cash-based incentive compensation included in:			
Lease operating expense [(1)]	3,500	849	2,206
General and administrative expenses [(1)]	10,086	4,019	8,897
Total charged to operating (loss) income	$ 16,950	$ 8,827	$ 14,793

(1) Includes adjustments of accruals to actual payments.

12. Employee Benefit Plan

We maintain 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 2021, 2020, and 2019 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). Our expenses relating to the 401(k) Plan were $2.0 million, $2.3 million, and $2.0 million for 2021, 2020 and 2019, respectively.

13. Income Taxes

Income Tax (Benefit) Expense

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

	Year Ended December 31,		
	2021	2020	2019
Current	$ 132	$ 134	$ (11,092)
Deferred	(8,189)	(30,287)	(64,102)
Total income tax (benefit) expense	$ (8,057)	$ (30,153)	$ (75,194)

Reconciliation

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

	Year Ended December 31,		
	2021	2020	2019
Income tax (benefit) expense at the federal statutory rate	$ (10,402)	$ 1,604	$ (233)
Compensation adjustments	559	1,373	971
State income taxes	(330)	75	(175)
Uncertain tax position	—	—	(11,523)
Impact of U.S. legislative changes	—	(21,345)	—
Valuation allowance	1,863	(12,018)	(64,704)
Other	253	158	470
Total income tax (benefit) expense	$ (8,057)	$ (30,153)	$ (75,194)

Our effective tax rate for the years 2021, 2020 and 2019 differed from the applicable federal statutory rate of 21.0% primarily due to the impact of the valuation allowance on our deferred tax assets, which is discussed below. As a result, our effective tax rate for 2021 is 16.3% while our effective tax rates for the years 2020 and 2019 presented above are 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 our deferred tax assets and liabilities were as follows (in thousands):

	December 31,	
	2021	2020
Deferred tax liabilities:		
Property and equipment	$ 55,170	$ 37,535
Derivatives	—	—
Investment in non-consolidated entity	4,659	8,070
Other	2,817	2,588
Total deferred tax liabilities	62,646	48,193
Deferred tax assets:		
Derivatives	21,026	3,416
Asset retirement obligations	91,850	84,332
Federal net operating losses	42,127	47,307
State net operating losses	7,612	8,136
Interest expense limitation carryover	18,628	16,304
Share-based compensation	312	419
Valuation allowance	(24,359)	(22,361)
Other	7,842	4,843
Total deferred tax assets	165,038	142,396
Net deferred tax assets (liabilities)	$ 102,392	$ 94,203

Income Taxes Receivable, Refunds and Payments

As of December 31, 2021 and 2020, we did not have any current income taxes receivable. During 2020 we received a refund of $2.0 million which related to a net operating loss ("NOL") carryback claim for the year 2017 that we carried back to prior years. This carryback claim was made pursuant to IRC Section 172(f) (related to rules regarding "specified liability losses"), which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. During the years ending December 31, 2021 and 2020, we did not make any tax payments of significance.

Net Operating Loss and Interest Expense Limitation Carryover

The table below presents the details of our net operating loss and interest expense limitation carryover as of December 31, 2021 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 200,605	earliest is 2037
State net operating loss	133,481	2026-2040
Interest expense limitation carryover	85,451	N/A

Valuation Allowance

During 2021, our valuation allowance increased $2.0 million primarily due to an increase in our disallowed interest expense limitation carryover. During 2020, we recorded a decrease in the valuation allowance of $32.1 million; resulting in an income tax benefit in 2020 primarily as a result of the enactment of the CARES Act on March 27, 2020 and the issuance by the United States Treasury Department (Treasury) of final and proposed regulations under Internal Revenue Code (“IRC”) Section 163(j) on July 28, 2020 that provided additional guidance and clarification to the business interest expense limitation. 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 our ability to realize our 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. Although the Company incurred a loss in 2021, we determined that these results were not indicative of future results and concluded that the positive evidence outweighed the negative evidence. The portion of the valuation allowance remaining relates to state net operating losses, charitable contributions carryover and the disallowed interest limitation carryover under IRC section 163(j). As of December 31, 2021, the Company’s valuation allowance was $24.4 million.

Years open to examination

The tax years from 2018 through 2021 remain open to examination by the tax jurisdictions to which we are subject.

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,		
	2021	2020	2019
Net (loss) income	$ (41,478)	$ 37,790	$ 74,086
Less portion allocated to nonvested shares	—	437	1,371
Net (loss) income allocated to common shares	$ (41,478)	$ 37,353	$ 72,715
Weighted average common shares outstanding - basic	142,271	141,622	140,583
Dilutive effect of securities	—	1,655	3,141
Weighted average common shares outstanding - diluted	142,271	143,277	143,724
Earnings per common share:			
Basic	$ (0.29)	$ 0.26	$ 0.52
Diluted	$ (0.29)	$ 0.26	$ 0.52
Shares excluded due to being anti-dilutive (weighted-average)	1,370	—	—

15. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2021	2020	2019
Supplemental cash items:			
Cash and cash equivalents	$ 245,799	$ 43,726	$ 32,433
Restricted cash and restricted cash equivalents	4,417	—	—
Cash paid for interest	64,805	59,183	66,720
Cash paid for income taxes	152	159	51
Cash refunds received for income taxes	1	2,007	51,833
Cash received for interest income	112	603	7,720
Non-cash investing activities:			
Accruals of property and equipment	9,464	3,035	29,662
ARO - additions, dispositions and revisions, net	36,175	17,928	37,440

16. Commitments

Pursuant to the Purchase and Sale Agreement with Total E&P, we 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. Once the threshold is met for that year, excess funds in the escrow account are returned to us. As of December 31, 2021, we had surety bonds related to the agreement with Total E&P totaling $96.7 million and had no amounts in escrow. The threshold escalates to $103.0 million for 2023 in $3.0 million per year increments.

Pursuant to the Purchase and Sale Agreement with Shell Offshore Inc. ("Shell") related to ARO for certain properties, we have surety bonds that are subject to re-appraisal by either party. As of December 31, 2021, neither party had requested a re-appraisal to be made. The current security requirement of $64.0 million, which we have met, could be increased up to $94.0 million depending on certain conditions and circumstances.

Pursuant to the Purchase and Sale Agreement with Exxon related to ARO for certain properties, we were required to obtain $33.0 million of surety bonds as of December 31, 2021. This amount increases on June 1 of the following years to $36.3 million - 2022; $40.0 million - 2023; $44.0 million - 2024; $48.3 million - 2025; $53.2 million - 2026, and future increases in increments ranging $5.3 million to $10.4 million per year until the total amount reaches $114.0 million in 2034. We may request a redetermination with Exxon every two years by providing certain documentation as provided in the purchase agreement. We are 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 Purchase and Sale Agreement with Conoco related to ARO for certain properties, we were required to obtain $49.0 million of surety bonds and are required to maintain this level of bonds until the properties are fully plugged, abandoned, and restored in accordance with applicable laws and regulations.

During 2021, 2020 and 2019, we had surety bonds primarily related to our decommissioning obligations or ARO. Total expenses related to surety bonds, inclusive of the surety bonds in connection with the agreements described above, were $6.0 million, $5.4 million, and $4.7 million during 2021, 2020 and 2019, respectively. The amount of future commitments is dependent on rates charged in the market place and when asset retirements are completed. Estimated future expenses related to surety bonds were based on current market prices and estimates of the timing of asset retirements, of which some wells and structures are estimated to extend to 2065. Future payment estimates are (in millions):

2022	$	7.3
2023		6.1
2024		6.1
2025		6.0
2026		5.1
Thereafter		50.9
Total	$	81.5

Future surety bond costs may change due to a number of factors, including changes and interpretations of regulations by the BOEM.

In conjunction with the purchase of an interest in the Heidelberg field, we assumed contracts with certain pipeline companies that contain minimum quantities obligations that extend to 2021. For 2021, 2020 and 2019 expense recognized for the difference between the quantities shipped and the minimum obligations was $2.1 million, $4.5 million and $4.5 million, respectively. As of December 31, 2021, the estimated future costs are (in millions):

2022	$	1.8
2023		1.2
2024		0.9
2025		0.6
2026		0.4
Thereafter		0.4
Total	$	5.3

As of December 31, 2021 we have drilling commitments of $2.9 million for 2022. We do not have any long-term drilling rig commitments as of December 31, 2021.

See *Note 8 – Leases* for information on leases.

17. Related Parties

During 2021, 2020 and 2019, there were certain transactions between us and other companies our Chief Executive Officer, Tracy W. Krohn (“CEO”) either controlled or in which he had an ownership interest. Our 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 $0.6 million, $0.3 million and $1.2 million for the years 2021, 2020 and 2019 respectively.

Our CEO has ownership interests in certain wells operated by us (such ownership interests pre-date our initial public offering). Revenues are disbursed and expenses are collected in accordance with ownership interest. Proportionate insurance premiums were paid to us and proportionate collections of insurance reimbursements attributable to damage on certain wells were disbursed.

A company that provides marine transportation and logistics services to W&T employs the spouse of our 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 $12.0 million, $14.4 million and $22.8 million in 2021, 2020 and 2019, respectively. The spouse received commissions partially based on services rendered to W&T which were approximately $0.1 million in 2021, 2020 and 2019.

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

During 2021, pursuant to the Ninth Amendment to the Sixth Amended and Restated Credit Agreement, Calculus, an entity indirectly owned and controlled by our CEO, became the sole lender under our Credit Agreement. In relation to the execution of the Ninth Amendment, the Company paid Calculus an arrangement fee of approximately $0.8 million and paid legal fees on behalf of Calculus of approximately $0.2 million. See *Note 2 – Debt* for information on the related party transaction concerning Calculus.

See *Note 5 – Joint Venture Drilling Program* for information on a related party transaction concerning Monza.

18. Contingencies

Appeal with ONRR

In 2009, we recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited our calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance with the offset to a liability reserve; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the Interior Board of Land Appeals ("IBLA") under the DOI. On January 27, 2017, the IBLA affirmed the decision of the ONRR requiring W&T to pay approximately $4.7 million in additional royalties. We filed a motion for reconsideration of the IBLA decision on March 27, 2017. Based on a statutory deadline, we filed an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana. We were required to post a bond in the amount of $7.2 million and cash collateral of $6.9 million in order to appeal the IBLA decision. On December 4, 2018, the IBLA denied our motion for reconsideration. On February 4, 2019, we filed our first amended complaint, and the government has filed its Answer in the Administrative Record. On July 9, 2019, we filed an Objection to the Administrative Record and Motion to Supplement the Administrative Record, asking the court to order the government to file a complete privilege log with the record. Following a hearing on July 31, 2019, the Court ordered the government to file a complete privilege log. In an Order dated December 18, 2019, the court ordered the government to produce certain contracts subject to a protective order and to produce the remaining documents in dispute to the court for *in camera* review. Ultimately, the court upheld the government's assertion of privilege and the parties commenced briefing on the merits. At this point, 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, we are waiting for the district court's ruling on the merits. In January 2020, the cash collateral in the amount of $6.9 million securing the appeal bond in this matter was released to us. In compliance with the ONRR's request for W&T to increase the surety posted in the appeal, the sum of the bond posted is currently $8.2 million.

Royalties-In-Kind ("RIK")

Under a program of the Minerals Management Service ("MMS") (a Department of Interior ("DOI") agency and predecessor to the ONRR), royalties must be paid "in-kind" rather than in value from federal leases in the program. The MMS added to the RIK program our lease at the East Cameron 373 field beginning in November 2001, where in some months we over delivered volumes of natural gas and under delivered volumes of natural gas in other months for royalties owed. The MMS elected to terminate receiving royalties in-kind in October 2008, causing the imbalance to become fixed for accounting purposes. The MMS ordered us to pay an amount based on its interpretation of the program and its calculations of amounts owed. We disagreed with MMS's interpretations and calculations and filed an appeal with the IBLA, of which the IBLA ruled in MMS' favor. We filed an appeal with the District Court of the Western District of Louisiana, who assigned the case to a magistrate to review and issue a ruling, and the District Court upheld the magistrate's ruling on May 29, 2018. We filed an appeal on July 24, 2018. Part of the ruling was in favor of our position and part was in favor of MMS' position. We appealed the ruling to the U.S. Fifth Circuit Court of Appeals and the government filed a cross-appeal. The Fifth Circuit issued its ruling on December 23, 2019, holding that, while the DOI has statutory authority to switch the method of royalty payment from volumes ("in-kind") to cash ("in value"), the "cashout" methodology that the DOI ordered W&T to implement was unenforceable because that methodology was a "substantive rule" that the DOI adopted in violation of the Administrative Procedure Act. In addition, the Fifth Circuit held that the DOI's claim was unlawfully inflated because DOI improperly failed to give W&T credit for all royalty volumes delivered. The Fifth Circuit remanded the case to the District Court to implement the court's decision on appeal. Based on the combination of (i) the DOI's concessions concerning the scope of W&T's liability (e.g., that W&T is only liable for its working interest share of the royalty volumes at issue), and (ii) the Fifth Circuit's ruling, we estimate that the value of the DOI's claim against W&T is no greater than $250,000 and have adjusted the liability reserve for this matter as of December 31, 2021 to such amount.

Notices of Proposed Civil Penalty Assessment

In January 2021, we executed a Settlement Agreement with BSEE which resolved nine pending civil penalties issued by BSEE. The civil penalties pertained to INCs issued by BSEE alleging regulatory non-compliance at separate offshore locations on various dates between July 2012 and January 2018, 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 installment was paid in March 2021. In addition, W&T committed to implement a Safety Improvement Plan with various deliverables due over a period ending in 2022. In September 2021, we paid $40,200 related to an INC issued in 2018. Additionally in September 2021, we were notified of a new proposed civil penalty assessment for $46,000 for an INC that occurred at one of our properties in 2018, which we subsequently paid in January 2022.

Supplemental Bonding Requirements by the BOEM

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to satisfy lease obligations, including decommissioning activities on the OCS. As of the filing date of this Form 10-K, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to assurance obligations. W&T and other offshore Gulf of Mexico producers may in the ordinary course receive future demands for financial assurances from the BOEM as the BOEM continues to reevaluate its requirements for financial assurances.

Surety Bond Issuers' Collateral Requirements

The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for plugging and abandonment activities. We may be required to post collateral at any time pursuant to the terms of our agreement with various sureties under our existing bonds, if they so demand at their discretion. We did not receive any such collateral demands from surety bond providers during 2021 or 2020.

Retained Liabilities Related to Divested Property Interests

We may be subject to retained liabilities with respect to certain divested property interests by operation of law. For example, recent historical declines in commodity prices created an environment where there is an increased risk that owners and/or operators of interests purchased from us may no longer be able to satisfy plugging or abandonment obligations that attach to those interests. In that event, due to operation of law, we may be required to assume plugging or abandonment obligations for those interests. 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 we previously divested, we recorded a loss contingency accrual of $4.5 million related to the anticipated cost to decommission certain wells, pipelines, and production facilities for which we may receive decommissioning orders from BSEE. We no longer own these assets nor are they related to our current operations. We intend to seek contribution from other parties that owned an interest in the facilities. Potential recoveries from other parties that previously owned an interest in these wells, pipelines, and production facilities have not been recognized as of December 31, 2021.

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.

19. Supplemental Oil and Gas Disclosures—UNAUDITED

Geographic Area of Operation

All of our proved reserves are located within the United States in the Gulf of Mexico. Therefore, the following disclosures about our costs incurred, results of operations and proved reserves are on a total-company basis.

Capitalized Costs

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

	Year Ended December 31,		
	2021	2020	2019
Net capitalized costs:			
Proved oil and natural gas properties and equipment	$ 8,636.4	$ 8,567.5	$ 8,532.2
Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities	(7,981.3)	(7,890.9)	(7,793.3)
Net capitalized costs related to producing activities	$ 655.1	$ 676.6	$ 738.9

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

The following costs were incurred in oil and gas acquisition, exploration, and development activities (in millions):

	Year Ended December 31,		
	2021	2020	2019
Costs incurred: (1)			
Proved properties acquisitions	$ 2.2	$ 8.1	$ 223.8
Exploration (2)	47.3	7.4	30.6
Development	18.4	23.6	114.5
Total costs incurred in oil and gas property acquisition, exploration and development activities	$ 67.9	$ 39.1	$ 368.9

(1) Includes net additions from capitalized ARO of $36.2 million, $15.2 million, and $37.5 million during 2021, 2020, and 2019, respectively. These adjustments for ARO are associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.

(2) Includes seismic costs of $0.1 million, $0.3 million, and $7.8 million incurred during 2021, 2020, and 2019, respectively. Includes geological and geophysical costs charged to expense of $5.7 million, $4.5 million, and $5.7 million during 2021, 2020, and 2019, respectively.

Depreciation, depletion, amortization and accretion expense

The following table presents our depreciation, depletion, amortization and accretion expense per barrel equivalent (“Boe”) of products sold:

	Year Ended December 31,		
	2021	2020	2019
Depreciation, depletion, amortization and accretion ($/Boe)	$ 8.15	$ 7.82	$ 10.01

Oil and Natural Gas Reserve Information

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve information represents estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available. Decreases in the prices of oil, NGLs and natural gas could have an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. We are not the operator with respect to 25.3% of our proved developed non-producing reserves as of December 31, 2021 so we may not be in a position to control the timing of all development activities. We are the operator for substantially all of our proved undeveloped reserves as of December 31, 2021. In prior years, we were not the operator of substantially all proved undeveloped reserves.

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 and the FASB. The prices used do not purport, nor should it be interpreted, to present the current market prices related to our estimated oil and natural gas reserves. Actual future prices and costs may differ materially from those used in determining our proved reserves for the periods presented. The prices used are presented in the section below entitled "*Standardized Measure of Discounted Future Net Cash Flows"*.

The following sets forth estimated quantities of our net proved, proved developed and proved undeveloped oil, NGLs and natural gas reserves:

				Total Energy Equivalent Reserves (1)	
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Natural Gas Equivalent (Bcfe)
Proved reserves as of December 31, 2018	39.1	9.8	210.5	84.0	504.1
Revisions of previous estimates (2)	1.4	(1.5)	(16.9)	(3.0)	(18.2)
Extensions and discoveries (3)	0.9	0.1	1.2	1.1	6.7
Purchase of minerals in place (4)	3.1	17.4	417.6	90.1	540.9
Production	(6.7)	(1.3)	(41.3)	(14.8)	(89.0)
Proved reserves as of December 31, 2019	37.8	24.5	571.1	157.4	944.5
Revisions of previous estimates (5)	(0.9)	(5.9)	31.6	(1.4)	(8.8)
Extensions and discoveries (6)	0.2	—	0.2	0.2	1.3
Purchase of minerals in place (7)	0.7	0.5	14.8	3.6	21.8
Production	(5.6)	(1.7)	(48.4)	(15.4)	(92.3)
Proved reserves as of December 31, 2020	32.2	17.4	569.3	144.4	866.5
Revisions of previous estimates (8)	10.0	3.1	83.0	27.1	162.4
Extensions and discoveries	—	—	—	—	—
Purchase of minerals in place (9)	—	—	0.1	—	0.1
Production	(5.0)	(1.4)	(44.8)	(13.9)	(83.5)
Proved reserves as of December 31, 2021	37.2	19.1	607.6	157.6	945.5
Year-end proved developed reserves:					
2021	27.6	17.8	549.2	137.0	821.9
2020	24.0	16.5	550.2	132.2	793.3
2019	28.0	21.7	504.9	133.8	802.9
Year-end proved undeveloped reserves:					
2021(10)	9.6	1.3	58.4	20.6	123.8
2020	8.2	0.9	19.1	12.2	73.2
2019	9.8	2.8	66.2	23.6	141.6

(1) The conversion to barrels of oil equivalent and cubic feet equivalent were determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ significantly.

(2) Increases primarily related to upward revisions to our Ship Shoal 028 field and our Main Pass 108 field. Decreases of 10.0 MMBoe were due to price revisions for all proved reserves, which include estimated price revisions of the purchase of minerals in place from the date of purchase to December 31, 2019.

(3) Primarily related to extensions and discoveries of 0.9 MMBoe at our Mississippi Canyon 800 (Gladden) field.

(4) Primarily related to the Mobile Bay Properties and Magnolia acquisitions.

(5) Decreases of 27.7 MMBoe were due to price revisions for all proved reserves. increases of 26.2 MMBoe were primarily related to technical revisions at our Mobile Bay and Fairway properties.

(6) Primarily related to the discovery at East Cameron 338 field.

(7) Primarily related to the Mobile Bay Properties and Mahogany working interest acquisitions.

(8) Increases of 27.1 MMBoe were due to price revisions for all proved reserves.

(9) Primarily related to Main Pass working interest acquisitions.

(10) We believe that we will be able to develop all but 2.5 MMBoe (approximately 12%) of the total 20.6 MMBoe classified as PUDs at December 31, 2021, 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 existing well. Based on the latest reserve report, these PUD locations are expected to be developed in 2023 and 2024.

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to our proved oil and natural gas reserves together with changes therein. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices 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 FASB/SEC guidance. The average commodity prices weighted by field production and after adjustments related to the proved reserves are as follows:

	December 31,		
	2021	2020	2019
Oil ($/Bbl)	$ 65.25	$ 37.78	$ 58.11
NGLs ($/Bbl)	26.83	10.29	18.72
Natural gas ($/Mcf)	3.68	2.05	2.63

Future production, development costs and ARO are based on costs in effect at the end of each of the respective years with no escalations. Estimated future net cash flows, net of future income taxes, have been discounted to their present values based on a 10% annual discount rate.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and natural gas reserves. These estimates reflect proved reserves only and ignore, among other things, future changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2022 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is as follows (in millions):

	Year Ended December 31,		
	2021	2020	2019
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 5,178.2	$ 2,561.2	$ 4,153.8
Future costs:			
Production	(2,061.7)	(1,257.4)	(1,901.1)
Development and abandonment	(976.5)	(707.4)	(794.7)
Income taxes	(359.0)	(60.5)	(170.5)
Future net cash inflows before 10% discount	1,781.0	535.9	1,287.5
10% annual discount factor	(625.0)	(42.2)	(300.6)
Total	$ 1,156.0	$ 493.7	$ 986.9

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

	Year Ended December 31,		
	2021	2020	2019
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 493.7	$ 986.9	$ 1,067.0
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(370.5)	(168.6)	(315.8)
Net changes in price, net of future production costs	980.9	(503.7)	(376.4)
Extensions and discoveries, net of future production and development costs	—	2.8	27.0
Changes in estimated future development costs	(25.4)	(15.9)	(6.0)
Previously estimated development costs incurred	0.6	1.4	19.3
Revisions of quantity estimates	289.6	(65.2)	116.4
Accretion of discount	44.0	111.8	107.4
Net change in income taxes	(181.8)	87.7	62.9
Purchases of reserves in-place	0.5	44.6	298.3
Sales of reserves in-place	—	—	—
Changes in production rates due to timing and other	(75.6)	11.9	(13.2)
Net (decrease) increase	662.3	(493.2)	(80.1)
Standardized measure, end of year	$ 1,156.0	$ 493.7	$ 986.9

20. Subsequent Events

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 working 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 approximately $30.2 million was paid to the sellers.

On March 8, 2022, the Company entered into the Tenth Amendment to Sixth Amended and Restated Credit Agreement and Extension Agreement, which extended the maturity date and Lender commitment to January 3, 2023 for the short-term $100.0 million first priority lien secured revolving facility with a borrowing base of $50.0 million provided by Lender to the Borrower, subject to the satisfaction of customary closing conditions.

Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that any information relating to us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have each concluded that as of December 31, 2021 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2021, is set forth in "*Management's Report on Internal Control over Financial Reporting*" included under Part II, Item 8 in this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2021, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included under Part II, Item 8 in this Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

On March 8, 2022, the Company entered into the Tenth Amendment to Sixth Amended and Restated Credit Agreement and Extension Agreement, among (i) W&T Offshore, Inc., as Borrower, (ii) each Borrower guarantor subsidiary, (iii) Calculus Lending, LLC, as Lender, and (iv) Alter Domus (US) LLC, as Administrative Agent for the Lender, which extended the maturity date and Lender commitment to January 3, 2023 for the short-term $100.0 million first priority lien secured revolving facility with a borrowing base of $50.0 million provided by Lender to the Borrower, subject to the satisfaction of customary closing conditions. Calculus Lending, LLC is an affiliate of, and controlled by, Tracy W. Krohn, current Chief Executive Officer and President of the Company. The terms of the Tenth Amendment were approved by the Audit Committee of the Board of Directors of the Company.

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 report:

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	Second Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company’s Current Report on Form 8-K, filed March 22, 2019 (File No. 001-32414))
4.1	Indenture, dated as of October 18, 2018, by and among W&T Offshore, Inc., W&T Energy VI, LLC, and W&T Energy VII, LLC, as subsidiary guarantors the Guarantors (as defined) and Wilmington Trust, National Association, as trustee (including form of 9.75% Senior Second Lien Notes due 2023) (Incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K, filed on October 24, 2018 (File No. 001-32414))
4.2	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))
10.3	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006 (Incorporated by reference to Exhibit 10.2 of the Company’s Current Report on Form 8-K, filed July 12, 2006 (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 and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors (Incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 (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 September 18, 2018, by and between 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, Second Lien Collateral Trustee, Third Lien Collateral Trustee and Third Lien Trustee and Cortland Capital Market Services LLC, Priority Lien Agent. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed on October 24, 2018 (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 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-Kfor 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 8, 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	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)).

10.25	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)).
10.26*	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 10.5 to the Company's Quarterly Report on Form 10-Q, filed August 8, 2021 (File No. 001-32414)).
10.27*	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, 2021 (File No. 001-32414)).
10.28	Purchase and Sale Agreement, dated as of January 1, 2019, between Exxon Mobil Corporation, Mobil Oil Exploration & Producing Southeast Inc., XH, LLC, Exxon Mobile Bay Limited Partnership, ExxonMobil U.S. Properties Inc. and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed August 1, 2019 (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 or 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 report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 9, 2022.

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 report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 9, 2022.

/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 and 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%
W & T Energy VI, LLC	Delaware	100.0%
W & T Energy VII, LLC	Delaware	100.0%
White Shoal Pipeline Corporation	Delaware	73.4%

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%
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 9, 2022, 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, 2021.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 9, 2022

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent consultants, Netherland, Sewell & Associates, Inc. hereby consents to the incorporation by reference in the Annual Report on Form 10-K of W&T Offshore, Inc. to be filed on or about March 9, 2022, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated January 24, 2022, 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, 2021", and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2017, 2018, 2019, and 2020. We further consent to the incorporation by reference of information contained in our report dated January 24, 2022, 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/ C.H. (SCOTT) REES III, P.E.
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
March 9, 2022

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 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 9, 2022

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

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 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 9, 2022

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

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 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 period ended December 31, 2021 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 9, 2022	/s/ Tracy W. Krohn
	Tracy W. Krohn Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)
Date: March 9, 2022	/s/ Janet Yang
	Janet Yang Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)

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

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN
RICHARD B. TALEY, JR.

Chairman & CEO
C.H. (Scott) Rees III

President & COO
DANNY D. SIMMONS

January 24, 2022

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, 2021, 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, 2021, to be:

	Net Reserves			Future Net Revenue(1) (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	20,828.8	16,416.4	507,853.0	1,886,100.3	1,185,247.8
Proved Developed Non-Producing	6,804.7	1,393.0	41,341.6	376,399.7	222,886.5
Proved Undeveloped	9,602.0	1,287.4	58,449.7	421,576.2	213,719.0
Total Proved	37,235.5	19,096.8	607,644.2	2,684,076.1	1,621,853.4

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 $66.55 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.598 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $65.25 per barrel of oil, $26.83 per barrel of NGL, and $3.680 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.

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.
Chairman and Chief Executive Officer

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

Date Signed: January 24, 2022

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

Date Signed: January 24, 2022

GSC:ARS

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

DEFINITIONS OF OIL AND GAS RESERVES

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

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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

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

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

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

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

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

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

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