**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, 2020

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 $213,418,732 based on the closing sale price of $2.28 per share as reported by the New York Stock Exchange on June 30, 2020.

The number of shares of the registrant's common stock outstanding on February 28, 2021 was 142,304,770.

**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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**FORWARD-LOOKING STATEMENTS**

*This Annual Report on Form 10-K ("Form 10-K") contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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 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.

*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. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

*BSEE*. Bureau of Safety and Environmental Enforcement. The agency is responsible for enforcement of safety and environmental regulations. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

*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.

*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.

*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. These are created during the processing of natural gas.

*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.

## 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 subsidiary, W&T Energy VI, LLC, a Delaware limited liability company and through our proportionately consolidated interest in Monza Energy, LLC ("Monza"), as described in more detail in *Financial Statements and Supplementary Data – Note 4 – 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 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 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") extracted from natural gas).  In addition, the prices of goods and services used in our business can vary and impact our cash flows.

*COVID-19 Impacts on Economic Environment.* Due to circumstances related to the outbreak of COVID-19, various measures have been taken by federal, state and local governments to reduce the rate of spread of COVID-19. These measures and other factors have resulted in a decrease of general economic activity and a corresponding decrease in global and domestic energy demand impacting commodity pricing. In addition, actions by the Organization of Petroleum Exporting Countries and other high oil exporting countries like Russia ("OPEC+") negatively impacted crude oil prices during early 2020. These rapid and unprecedented events pushed crude oil storage near capacity and drove prices down significantly in the second quarter of 2020. These events were the primary cause of the significant supply-and-demand imbalance for oil, significantly lowering oil pricing in 2020 compared to the prior year. Throughout the United States during 2020, COVID-19 outbreaks continued and, in some areas, increased. Should these conditions continue in future periods, they could constrain our ability to store and move production to downstream markets, delay or curtail development activity or temporarily shut-in production, any or all of which could further reduce our cash flow.

*Hurricanes Impact on our Production.* Beginning in the second quarter of 2020 and extending through October 2020, the Gulf of Mexico experienced numerous hurricanes and tropical storms that required us to shut-in production at times due to their impact. We have since returned substantially all wells to production that were shut-in due to the hurricanes and tropical storms, as have operators of properties in which we have an interest. While no major structural damage occurred, we incurred $4.7 million in repairs costs during 2020 associated with repairs to our assets caused by storm events in 2020. See "*Risk Factors" – "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.*"

During 2020, average realized commodity prices decreased from those we experienced during 2019. Our margins in 2020 decreased from 2019 primarily due to lower average realized commodity prices, partially offset by lower operating expenses as a result of our cost-cutting efforts in 2020. We measure margins using net income (loss) 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; litigation; and other ("Adjusted EBITDA") as a percent of revenue, which is a not a financial measurement under generally accepted accounting principles ("GAAP").

Our production increased 3.8 % in 2020 from the prior year. Our proved reserves decreased by 13.0 million barrels of oil equivalent ("MMBoe") in 2020, primarily due to the significant decline in commodity prices in 2020 as compared to 2019. MMBoe was computed on an equivalency ratio as described above. During 2020, we drilled one well which we expect to complete in 2021.

We continue to closely monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2021 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 2020, approximately 39% of our revenues were received from BP Products North America, 13% to Williams Field Services and 10% to Mercuria Energy America Inc. Trading (US) Co., with no other customer comprising greater than 10% of our 2020 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 volumes of physical products to customers.

**Compliance with Government Regulations**

*General.* 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 entered office in January 2021 and 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, the Acting Secretary of the U.S. Department of the Interior issued an order on January 20, 2021, effective immediately, that suspends new oil and gas leases and drilling permits on federal lands and offshore waters, including the OCS for a period of 60 days. Building on this suspension, President Biden issued an executive order on January 27, 2021 that suspends 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. While these January 20, 2021 and January 27, 2021 orders do not apply to existing leases, the January 27, 2021 order further directs applicable agencies to take measures to eliminate provision of subsidies to the fossil fuel industry, although the term "subsidies" is not defined by the adminstration. We continue to conduct our operations on our existing leases in the OCS; however, uncertainty on future Biden Administration actions with regards 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 ("NTL") #2016-N01 ("NTL #2016-N01") 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"). While NTL #2016-N01 became effective in September 2016, it was not fully implemented as the BOEM under the Trump Administration first extended indefinitely in 2017 implementation of the NTL and subsequently rescinded the NTL in the latter half of 2020, instead electing to publish in October 2020 a proposed rule that would amend the BOEM's financial assurance requirements. The Biden Administration is expected to review and reconsider actions made under the Trump Administration with respect to provision of financial assurance, including the rescission of NTL #2016-N01 and publication of the October 2020 proposed rulemaking. Any issuance by the Biden Administration of more stringent NTL guidance or rules relating to the provision of additional financial assurance may have a material adverse effect on us and similarly situated offshore oil and gas operators on the OCS. Moreover, 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.

*Unbundling.* The ONRR has publicly announced an "unbundling" initiative to revise the methodology employed by producers in determining the appropriate allowances for transportation and processing costs that are permitted to be deducted in determining royalties under Federal oil and gas leases. The ONRR's initiative requires re-computing allowable transportation and processing costs using revised guidance from the ONRR going back 84 months for every gas processing plant utilized during that period.

*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*. Our sales of liquids, which include crude oil, condensate and NGLs are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction. The price we receive from the sale of crude oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for crude oil, condensate, NGLs and other products are regulated by the FERC. In general, interstate crude oil, condensate and NGL pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. The FERC has established an indexing system for such transportation, which generally allows such pipelines to take an annual inflation-based rate increase.

In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes and regulations. As it relates to intrastate crude oil, condensate and NGL pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally. We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or NGL pipelines will affect us in a way that materially differs from the way they affect other crude oil, condensate and NGL producers or marketers.

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

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. 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; 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 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, on December 31, 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 NAAQS may be subject to revision under the Biden Administration.

In the United States, no comprehensive climate change legislation has been implemented at the federal level, but President Biden is expected to issue executive orders or pursue legislative or regulatory actions to limit future GHG emissions. For example, on January 20, 2021, President Biden issued an executive order committing the United States to the Paris Agreement, from which the United States had withdrawn under the Trump Administration. President Biden has called for the federal government to begin formulating the United States' nationally determined emissions reduction goal under the agreement, which may result in the issuance of GHG limitations in the future. Additionally, the threat of climate change may result in litigation and financial risks. Litigation risks are increasing, as a number of states, municipalities and other plaintiffs have sought to bring suit against the largest oil and natural gas exploration and production 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 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 by failing to adequately disclose those impacts. There are also increasing financial risks for fossil fuel producers as well as other companies handling fossil fuels, as stockholders and bondholders currently invested in fossil fuel energy companies 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 investors who provide financing to fossil fuel energy companies also have become more attentive to sustainability lending practices and some of them may elect not to provide funding for fossil fuel energy companies.

From a regulatory perspective, the EPA has determined that GHG emissions present a danger to public health and the environment, and it has adopted regulations that, among other things, restrict emissions of GHG under existing provisions of the CAA and may require the installation of control technologies to limit emissions of GHG.  For example, in 2016, the EPA under the Obama administration published a final rule establishing new source performance standards ("NSPS") that require new, modified, or reconstructed facilities in the oil and natural gas sector to reduce methane gas and volatile organic compound emissions.  The 2016 rule applies to any new or significantly modified facilities that we construct in the future that would otherwise emit large volumes of GHG together with other criteria pollutants.  The 2016 new source performance standards regulate GHGs through limitations on emissions of methane.  However, the EPA under the Trump Administration has undertaken several measures, including publishing in September 2020 final rule policy and technical amendments to the NSPS, for stationary sources of air emissions. The policy amendments, effective September 14, 2020, notably removed the transmission and storage sector from the regulated source category and rescinded methane and volatile organic compound requirements for the remaining sources that were established by former President Obama's Administration, whereas the technical amendments, effective November 16, 2020, included changes to fugitive emissions monitoring and repair schedules, recordkeeping and reporting requirements, and more. Various states and industry and environmental groups are separately challenging both the original 2016 standards and the EPA's September 2020 final rules, and on January 20, 2021, President Biden issued an executive order, that among other things, directed EPA to reconsider the technical amendments and issue a proposed rule suspending, revising or rescinding those amendments by no later than September 2021. A reconsideration of the September 2020 policy amendments is expected to follow. The January 20, 2021 executive order also directed the establishment of new methane and volatile organic compound standards applicable to existing oil and gas operations, including the production, transmission, processing and storage segments. Certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified offshore production sources.

The OCSLA authorized the DOI to regulate activities authorized by the BOEM in the Central and Western Gulf of Mexico.  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.

On May 14, 2020, the BOEM issued its final rule to update air quality regulations applicable to activities authorized by BOEM on the OCS in the Central and Western Gulf of Mexico.  This newly revised rule adopted changes such as incorporation of the definition of the NAAQS, updated Significance Levels (SLs), added new requirements for PM2.5 and PM10, updates to emissions exemption thresholds and revision to the Air Quality Spreadsheets.

*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 $150.0 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.

*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 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 on January 7, 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. While the rule was scheduled to become effective on February 8, 2021, the USFWS subsequently published notice on February 9, 2021, that it was delaying the effective date of this rule until March 8, 2021, pursuant to the Biden Administration and in conformity with the Congressional Review Act. 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, such as has occurred under the Biden Administration's DOI order issued on January 20, 2021 with respect to drilling permits, or cancellation of such programs.

**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**

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 require us to evacuate personnel and shut in production until the 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.

**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, 2020, our personnel base consisted of 303 of our employees and over 300 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 2020 total recordable incident rate ("TRIR") for employees was 0.3, which is far below the industry average for the Gulf of Mexico of 0.5. Our Health, Safety and Environmental ("HS&E") group is comprised of a Vice President, and Environmental, Safety and Regulatory Managers and 10 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.

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, and limiting headcount to 50% or less in our offices during peak COVID-19 outbreaks in the community.

*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.

*Diversity and Inclusion.* The key to our past and future successes is promoting a workforce culture that embraces integrity, honesty and transparency those we interact, 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, 2020:

| Category | Female | Male |
|---|---|---|
| Exec/Sr. Manager | 20% | 80% |
| Mid-Level Manager | 17% | 83% |
| Professionals | 48% | 52% |
| All Other | 9% | 91% |

| US Ethnicity | Exec/Sr. Manager | Mid-Level Manager | Professionals | All Other |
|---|---|---|---|---|
| Asian | 40% | 6% | 12% | — |
| Black/African American | 20% | 8% | 24% | 5% |
| Hispanic/Latino | — | 2% | 12% | 7% |
| Native American | — | — | — | 1% |
| Two or more races | — | 2% | — | 1% |
| White | 40% | 82% | 52% | 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 following the COVID-19 pandemic);
- the actions of the Organization of Petroleum Exporting Countries (“OPEC”) and major oil producing countries;
- 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;
- 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;
- 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 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, as we experienced in 2020. While we have not recorded an impairment of our oil and gas properties during the year-ended December 31, 2020, 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, and as required under the Sixth Amended and Restated Credit Agreement (the "Credit Agreement"), we enter into oil and natural gas price commodity derivative positions with respect to a portion of our expected production. See *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for a full description the Credit Agreement. 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, 2020, three fields, accounting for approximately 0.1 MMBoe (or 1%) of our 2020 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 32% of our total proved reserves as of December 31, 2020 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 $150.0 million that can be used to cover costs that could be incurred in responding to an oil spill our facilities on the OCS. 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 – Hurricane Remediation, Insurance Claims and 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, 2020.

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 have significantly reduced global economic activity, resulting in a decline in the demand for oil, natural gas, and other commodities. These economic consequences have been a primary cause of the significant supply-and-demand imbalance for oil. The current supply-and-demand imbalance and significantly lower oil pricing 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.

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 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 *Executive Officers of the Registrant* under Part I following Item 3 in 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, which may be reduced by our lenders. 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, 2020, we had $632.5 million in principal of indebtedness outstanding and $4.4 million of letters of credit obligations outstanding, substantially all of which is secured. During 2020, we incurred $61.5 million in interest expense. 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;
- impair our ability to obtain additional financing 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 lenders' 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 and 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 or reduce our debt. 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.

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.***

All of our existing indebtedness under our Credit Agreement and our outstanding Second Lien Senior Notes is secured by liens on substantially all of our oil, natural gas and NGL properties. In addition, we have certain rights to issue or incur additional or new secured debt, including up to $105.6 million as of January 6, 2021, available for borrowing under our Credit Agreement following the most recent redetermination, that would 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 any sale of the collateral are not sufficient to repay all amounts due in respect of our secured 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 recent election of President Biden and changes in U.S. Congress may result in significant legislative and regulatory changes that could adversely affect our results of operations, and our ability to implement our business strategy.***

Recently elected President Biden has indicated that his administration will pursue regulatory initiatives, executive actions and legislation in support of his regulatory and political agenda, which includes the reduction in dependence on, and use of, fossil fuels and curtailment of hydraulic fracturing on federal lands in response to climate change and other environmental risks. 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. Under certain circumstances, U.S. federal agencies may refuse to approve new leases for hydrocarbon exploration and development on federal lands and waters and may refuse to grant or delay approvals required for development of existing leases on such lands and waters. See Part I, Item 1. "Business – Compliance with Environmental Regulations" for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry that are being 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 Administration had sought to implement more stringent and costly standards under the existing federal financial assurance requirements through issuance and implementation of NTL #2016-N01, but former President Trump's Administration first paused, and then in 2020 rescinded, the implementation of this NTL while the BOEM issued a proposed rulemaking in October 2020 to amend its financial assurance program. The BOEM under the Biden Administration may in the future reconsider offshore financial assurance requirements, including the rescinded NTL #2016-N01 and the October 2020 proposed rule, and adopt and implement more stringent requirements. Moreover, the BOEM could make 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.***

President Biden and one or more of agencies under his administration has issued orders temporarily suspending leasing or permitting of oil and natural gas activities on federal lands and waters, including the OCS, and his administration is expected to pursue additional orders, legislation and regulatory initiatives 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, in recent years under the Trump Administration, there have been actions by BSEE or BOEM seeking to mitigate or delay certain of those more rigorous standards, we expect that the Biden Administration may reconsider rules and regulatory initiatives implemented under the Trump Administration. Compliance with any added and more stringent regulatory requirements and with 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, these 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. For example, under the Trump Administration, BSEE reviewed and delayed or revised certain offshore regulations implemented during the Obama Administration with respect to the imposition of rigorous standards relating to well control. In light of the statements made by President Biden, there exists a significant risk that these Obama-era regulations, or additional, more stringent regulations impacting our business, properties and results of operations could be reimplemented or adopted during the Biden Administration.

These regulatory actions, or any new rules, regulations, or legal 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 Environmental 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. In December 2018, BSEE issued an updated NTL reaffirming the obligations of offshore operators to timely decommission idle iron by means of abandonment and removal. Pursuant to the idle iron NTL requirements, in September 2019, 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, with the earliest deadline being December 31, 2020. 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 by BSEE as idle iron, but we do not expect the costs to plug and abandon these 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 2018 NTL 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.

The 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 otherwise 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 property interests that were sold several years prior. These indirect obligations would affect our costs, operating profits and cash flows negatively and could be substantial.

***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 – Regulation* 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 – 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.

**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, 2020, three of our fields located in the conventional shelf accounted for approximately 82% our proved reserves on an energy equivalent basis. The following table provides information for these fields:

| | Proved Reserves as of December 31, 2020 | | | | |
|---|---|---|---|---|---|
| | Oil (MMBbls) | NGLs (MMBbls) | Natural Gas (Bcf) | Oil Equivalent (MMBoe) | Percent of Total Company Proved Reserves |
| Mobile Bay Properties | 0.1 | 11.9 | 403.3 | 79.3 | 54.9% |
| Ship Shoal 349 (Mahogany) | 15.8 | 1.8 | 40.3 | 24.3 | 16.8% |
| Fairway | — | 2.2 | 75.0 | 14.7 | 10.2% |

The Mobile Bay Properties, Ship Shoal 349 (Mahogany), and Fairway are three 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 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. The field area includes 16 Alabama state water lease blocks and four Federal OCS lease blocks. These properties include seven major platforms and 27 flowing wells, in up to 50 feet of water. Exxon first discovered Norphlet gas play in 1978 with the first gas production from the Mary Ann Field in 1988. We acquired varied operated working interests 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 2020, we completed the purchase of the remaining interest in two federal Mobile Bay fields from Chevron U.S.A. Inc. ("Chevron"). Cumulative field production through 2020 is approximately 698.3 MMBoe gross. The Mobile Bay Properties produce from the Jurassic age Norphlet eolian sandstone at an average depth of 21,000' total vertical depth. As of December 31, 2020, 56 Norphlet wells have been drilled on the Mobile Bay Properties, 45 wells were successful and 27 wells are currently producing.

We acquired the Mobile Bay Properties in August 2019 and included the results of operations effective September 1, 2019 within our Consolidated Results of Operations. During September 2019 to December 2019, transitioning activities occurred to transfer operatorship of the Mobile Bay Properties from Exxon to W&T. (Given the limited history and the change in operatorship, production volumes, realized prices received and production costs are omitted.)

***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 in the Joint Venture Drilling Program. Cumulative field production through 2020 is approximately 56.6 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, 2020, 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 was no additional drilling activity during 2020 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, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| Net Sales: | | | |
| Oil (MBbls) | 1,939 | 2,444 | 1,719 |
| NGLs (MBbls) | 148 | 154 | 167 |
| Natural gas (MMcf) | 3,015 | 3,955 | 2,508 |
| Total oil equivalent (MBoe) | 2,590 | 3,257 | 2,307 |
| Total natural gas equivalents (MMcfe) | 15,539 | 19,545 | 13,841 |
| Average daily equivalent sales (Boe/day) | 7,076 | 8,925 | 6,320 |
| Average daily equivalent sales (Mcfe/day) | 42,456 | 53,547 | 37,920 |
| Average realized sales prices: | | | |
| Oil ($/Bbl) | $ 36.69 | $ 58.27 | $ 62.83 |
| NGLs ($/Bbl) | 14.46 | 21.96 | 31.14 |
| Natural gas ($/Mcf) | 1.92 | 2.53 | 3.41 |
| Oil equivalent ($/Boe) | 30.54 | 47.84 | 52.78 |
| Natural gas equivalent ($/Mcfe) | 5.09 | 7.97 | 8.80 |
| Average production costs: (1) | | | |
| Oil equivalent ($/Boe) | $ 4.98 | $ 4.77 | $ 4.87 |
| Natural gas equivalent ($/Mcfe) | 0.83 | 0.79 | 0.81 |

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

***Fairway Field***

The Fairway Field is comprised of Mobile Bay Area blocks 113 (Alabama State Lease #0531) and 132 (Alabama State Lease #0532) located in 25 feet of water, approximately 35 miles south of Mobile, Alabama. 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. ("Shell") in August 2011 and acquired the remaining working interest of 35.7% in September 2014. Cumulative field production through 2020 is approximately 136.4 MMBoe gross. The field was discovered in 1985 with Well 113 #1 (now called JA). Development drilling began in 1990 and was completed in 1991 with the addition of four wells, each drilled from separate surface locations. The five producing wells came on line in late 1991. As of December 31, 2020, six wells have been drilled, one of which was a replacement well. This field is a Norphlet sand dune trend development with one producing horizon at an approximate depth of 21,300 feet.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| Net Sales: | | | |
| Oil (MBbls) | 9 | 9 | 9 |
| NGLs (MBbls) | 265 | 305 | 315 |
| Natural gas (MMcf) | 5,329 | 5,918 | 5,673 |
| Total oil equivalent (MBoe) | 1,162 | 1,300 | 1,270 |
| Total natural gas equivalents (MMcfe) | 6,973 | 7,802 | 7,621 |
| Average daily equivalent sales (Boe/day) | 3,175 | 3,563 | 3,480 |
| Average daily equivalent sales (Mcfe/day) | 19,051 | 21,375 | 20,880 |
| Average realized sales prices: | | | |
| Oil ($/Bbl) | $ 38.52 | $ 62.25 | $ 66.63 |
| NGLs ($/Bbl) | 8.43 | 15.83 | 24.93 |
| Natural gas ($/Mcf) | 1.94 | 2.52 | 3.12 |
| Oil equivalent ($/Boe) | 11.12 | 15.61 | 24.54 |
| Natural gas equivalent ($/Mcfe) | 1.85 | 2.60 | 4.09 |
| Average production costs: (1) | | | |
| Oil equivalent ($/Boe) | $ 11.35 | $ 10.77 | $ 9.38 |
| Natural gas equivalent ($/Mcfe) | 1.89 | 1.80 | 1.56 |

(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, 2020 are summarized below:

| | | | | Total Energy-Equivalent Reserves (2) | | | |
|---|---|---|---|---|---|---|---|
| Classification of Proved Reserves (1) | Oil (MMBbls) | NGLs (MMBbls) | Natural Gas (Bcf) | Oil Equivalent (MMBoe) | Natural Gas Equivalent (Bcfe) | % of Total Proved | PV-10 (In millions) |
| Proved developed producing | 19.4 | 15.6 | 510.4 | 120.1 | 720.4 | 83% | $ 573.0 |
| Proved developed non-producing | 4.6 | 0.9 | 39.8 | 12.1 | 72.9 | 8% | 73.7 |
| Total proved developed | 24.0 | 16.5 | 550.2 | 132.2 | 793.3 | 91% | 646.7 |
| Proved undeveloped | 8.2 | 0.9 | 19.1 | 12.2 | 73.2 | 9% | 94.2 |
| Total proved | 32.2 | 17.4 | 569.3 | 144.4 | 866.5 | 100% | $ 740.9 |

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2020 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, 2020. Applying this methodology, the West Texas Intermediate ("WTI") average spot price of $39.54per barrel and the Henry Hub natural gas average spot price of $1.985per 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 realized prices were $37.78 per barrel for oil, $10.29 per barrel for NGLs and $2.05 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) 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.

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, 2020 |
|---|---|
| Present value of estimated future net revenues (PV-10) | $ 740.9 |
| Present value of estimated ARO, discounted at 10% | (204.2) |
| PV-10 after ARO | 536.7 |
| Future income taxes, discounted at 10% | (43.0) |
| Standardized measure of discounted future net cash flows | $ 493.7 |

***Changes in Proved Reserves***

Our total proved reserves at December 31, 2020 were 144.4 MMBoe compared to 157.4 MMBoe at December 31, 2019, representing an overall decrease of 13.0 MMBoe. Total proved reserves decreased by 27.7 MMBoe as a result of lower commodity prices and 15.4 MMBoe due to production. Partially offsetting these decreases were increases in proved reserves of 26.2 MMBoe due to positive technical revisions (including increased well performance), 3.6 MMBoe related to acquisitions, 0.2 MMBoe related to extensions and discoveries. See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2020. See *Financial Statements and Supplementary Data– Note 20 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

Our estimates of proved reserves, PV-10 and the standardized measure as December 31, 2020 are calculated based upon SEC mandated 2020 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 2020 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.

***Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process***

Our estimated proved reserve information as of December 31, 2020 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.

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.

***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, 2020 were estimated at $94.2 million.

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

| | December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| Proved undeveloped reserves, beginning of year | 23.6 | 17.0 | 12.0 |
| Transfers to proved developed reserves | — | (0.5) | (5.0) |
| Revisions of previous estimates | (11.4) | 7.1 | 11.3 |
| Extensions and discoveries | — | — | — |
| Purchase of minerals in place | — | — | 2.2 |
| Sales of minerals in place | — | — | (3.5) |
| Proved undeveloped reserves, end of year | 12.2 | 23.6 | 17.0 |

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 |
|---|---|---|
| 2021 | 1 | 22% |
| 2022 | 2 | 15% |
| 2023 | 1 | 59% |
| 2024 | 1 | 4% |
| Total | 5 | 100% |

Activity related to PUD in 2020:

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

We believe that we will be able to develop all but 2.3 MMBoe (approximately 19%) of the total 12.2 MMBoe classified as PUDs at December 31, 2020, within five years from the date such PUDs were initially recorded. The 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. One sidetrack PUD location at each Matterhorn and Virgo, will be delayed until an existing well are 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 2022 and 2024.

## Acreage

The following table summarizes our leasehold at December 31, 2020. Deepwater refers to acreage in over 500 feet of water:

| | Developed Acreage | | Undeveloped Acreage | | Total Acreage | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Shelf | 427,222 | 311,370 | 99,551 | 86,788 | 526,773 | 398,158 |
| Deepwater | 159,209 | 62,067 | 50,451 | 45,651 | 209,660 | 107,718 |
| Total | 586,431 | 373,437 | 150,002 | 132,439 | 736,433 | 505,876 |

Approximately 74% 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 132,439 net undeveloped acres none could expire in 2021; 960 net acres (1%) could expire in 2022; 37,166 net acres (28%) could expire in 2023; 80,293 net acres (60%) could expire in 2024; and 14,020 net acres (11%) could expire in 2025 and beyond. In making decisions regarding drilling and operations activity for 2020 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 41,688 net acres (8%) from December 31, 2019 due to lease expirations and relinquishments, partially offset by acquisitions.

## Production

For the years 2020, 2019 and 2018, our net daily production averaged 42,046 Boe, 40,634 Boe, and 36,510 Boe, respectively. Production increased in 2020 from 2019 primarily due a full year of production at the Mobile Bay properties. 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Net Sales: | | | |
| Oil (MBbls) | 5,629 | 6,675 | 6,687 |
| NGLs (MBbls) | 1,696 | 1,271 | 1,307 |
| Oil and NGLs (MBbls) | 7,325 | 7,946 | 7,994 |
| Natural gas (MMcf) | 48,384 | 41,310 | 31,991 |
| Total oil equivalent (MBoe) | 15,389 | 14,831 | 13,326 |
| Total natural gas equivalents (MMcfe) | 92,334 | 88,987 | 79,956 |

### Productive Wells

The following presents our ownership interest at December 31, 2020 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:

| Offshore Wells | Oil Wells (1) | | Gas Wells (2) | | Total Wells | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Operated | 85 | 74.1 | 67 | 58.8 | 152 | 132.9 |
| Non-operated | 39 | 8.4 | 22 | 7.8 | 61 | 16.2 |
| Total offshore wells | 124 | 82.5 | 89 | 66.6 | 213 | 149.1 |

(1) Includes six gross (4.2 net) oil wells with multiple completions.

(2) Includes three gross (2.5 net) gas wells with multiple completions.

### 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Development Wells Completed:** | | | |
| Gross wells | — | 3.0 | 3.0 |
| Net wells | — | 1.6 | 1.5 |
| **Exploration Wells Completed:** | | | |
| Gross wells | — | 3.0 | 3.0 |
| Net wells | — | 0.8 | 1.3 |

Our success rates related to our development and exploration wells drilled was 100% in both 2019 and 2018, with all wells drilled being productive and none were non-commercial (dry holes).

***Recent Drilling Activity***

During 2020, we drilled one well, which we expect to be completed in 2021.

### 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.

## 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 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 penal sum of the bond posted is currently $8.2 million.

***Monetary Sanctions by Government Authorities (Notices of Proposed Civil Penalty Assessment).*** During 2020 and 2019, we did not pay any civil penalties to the Bureau of Safety and Environmental Enforcement ("BSEE") related to Incidents of Noncompliance ("INCs") at various offshore locations. 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, with the first installment due in March 2021. In addition, W&T committed to implement a Safety Improvement Plan with various deliverables due over a period ending in 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.

**Executive Officers of the Registrant**

The following table lists our executive officers:

| Name | Age (1) | Position |
|---|---|---|
| Tracy W. Krohn | 66 | Chairman, Chief Executive Officer and President |
| Janet Yang | 40 | Executive Vice President and Chief Financial Officer |
| William J. Williford | 48 | Executive Vice President and General Manager of Gulf of Mexico |
| Stephen L. Schroeder | 58 | Senior Vice President and Chief Technical Officer |
| Shahid A. Ghauri | 52 | Vice President, General Counsel and Corporate Secretary |

(1) Ages as of February 23, 2021

*Tracy W. Krohn* has served as our Chief Executive Officer since he founded the Company in 1983, President from 1983 until 2008 and again starting in March 2017, Chairman of the Board since 2004 and Treasurer from 1997 until 2006. During 1996 to 1997, Mr. Krohn was Chairman and Chief Executive Officer of Aviara Energy Corporation. He began his career as a petroleum engineer and offshore drilling supervisor with Mobil Oil Corporation and then as Senior Engineer with Taylor Energy Company. Mr. Krohn serves on the board of directors for the American Petroleum Institute. He also serves on the board of directors of a privately owned company.

*Janet Yang* joined the Company in 2008 and was named Executive Vice President and Chief Financial Officer in November 2018. Previously, she served as Acting Chief Financial Officer from August 2018 to November 2018, Vice President – Corporate and Business Development from March 2017 to November 2018, Director Strategic Planning & Analysis from June 2012 to March 2017 and Finance Manager from December 2008 to June 2012. Prior to joining the Company, Ms. Yang held positions in research and investment analysis at BlackGold Capital Management, investment banking at Raymond James and energy trading at Allegheny Energy.

*William J. Williford* joined the Company in 2006 and was named Executive Vice President and General Manager of Gulf of Mexico in November 2018. Since joining W&T in 2006, he has served as Reservoir Engineer, Exploration Project Manager, General Manager Deepwater of Gulf of Mexico, and most recently, Vice President and General Manager of Gulf of Mexico Shelf and Deepwater. Mr. Williford has over 20 years of oil and gas technical experience with large independents in the Gulf of Mexico and Domestic Onshore. Prior to joining the Company, Mr. Williford held positions in reservoir, production and operations at Kerr-McGee and Oryx Energy.

*Stephen L. Schroeder* joined the Company in 1998 and was named Senior Vice President and Chief Technical Officer in June 2012. Previously, he served as Senior Vice President and Chief Operating Officer from July 2006 to June 2012, Vice President of Production from 2005 to July 2006 and Production Manager from 1999 until 2005. Prior to joining the Company, Mr. Schroeder was with Exxon USA for 12 years holding positions of increasing responsibility, ending with Offshore Division Reservoir Engineer.

*Shahid A. Ghauri* joined the Company in March 2017 as Vice President, General Counsel and Corporate Secretary. Prior to joining the Company, Mr. Ghauri served as a partner with Jones Walker, a New Orleans, Louisiana law firm since 2015. Prior to that, Mr. Ghauri served as Assistant General Counsel of BHP Billiton Petroleum and in private practice as a partner working with top tier oil and gas firms for 17 years.

Our management team's interests are highly aligned with those of our shareholders through our 34% stake in the Company's equity.

**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***

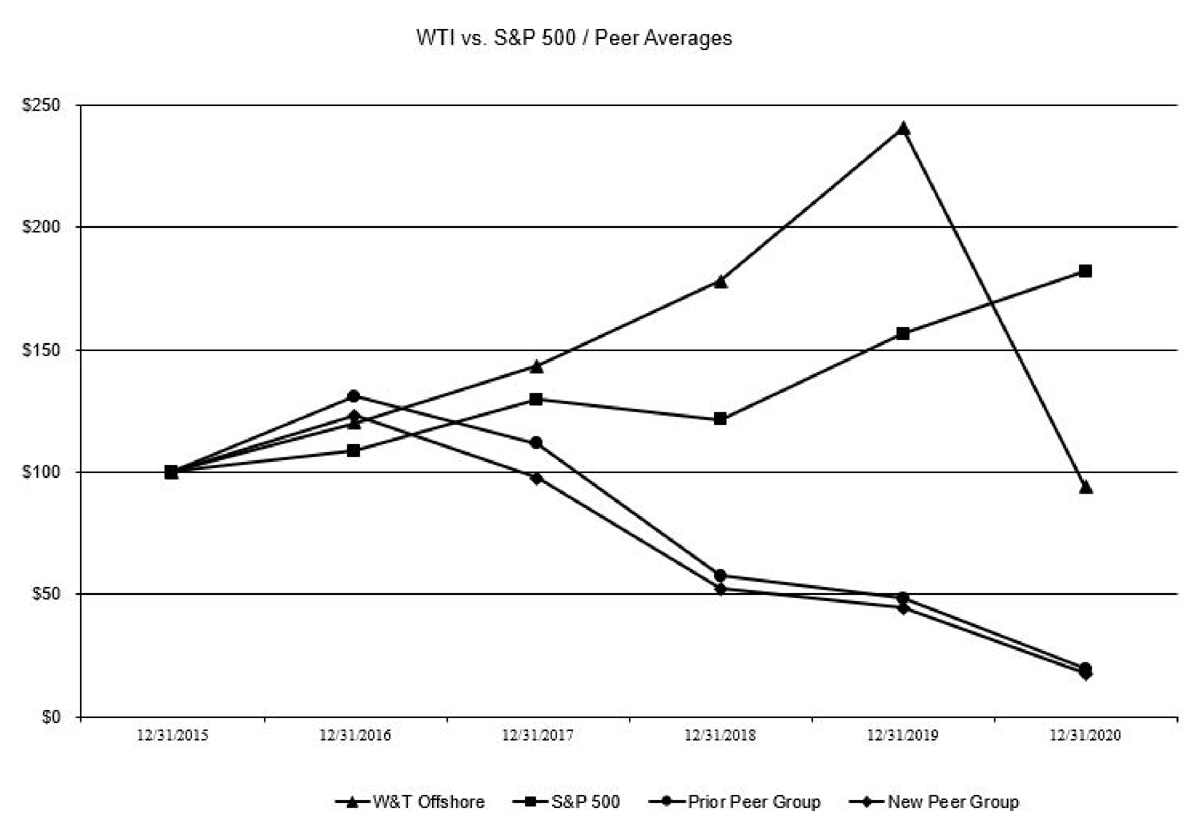
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of March 2, 2021, there were 172 registered holders of our common stock.

**Dividends**

During 2020 and 2019, 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 – Long-Term 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.



Our peer group was revised in 2020 ("New Peer Group") to be in alignment with the peer group used for executive compensation analysis. The New Peer Group no longer includes Abraxas Petroleum Corporation and Comstock Resources; however, Bonanza Creek Energy Inc.; Earthstone Energy Inc.; Gran Tierra Energy Inc.; Gulfport Energy Corporation; Highpoint Resources Corporation; Kosmos Energy Ltd.; Laredo Petroleum, Inc.; Northern Oil and Gas, Inc.; and Ring Energy, Inc. are still included. Companies used in the most recent executive compensation analysis but were excluded due to not having a five year trading history were Talos Energy, Inc.; Berry Corporation; SilverBow Resources, Inc.; Penn Virginia Corporation; and Centennial Resource Development, Inc. Montage Resources Corporation was included in our compensation analysis, but excluded from the above graph as their stock was not traded during all of 2020 due to being acquired by Southwestern Energy Company. Additionally, the New Peer Group includes QEP Resources, Inc.

**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 2020, 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, 2020:

| 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, 2020 – October 31, 2020 | N/A | N/A | N/A | N/A |
| November 1, 2020 – November 30, 2020 | N/A | N/A | N/A | N/A |
| December 1, 2020 – December 31, 2020 (1) | 260,751 | $ 2.57 | N/A | N/A |

(1) RSUs delivered by employees during December 2020 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, 2020 that we have not previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

**Item 6. Selected Financial Data**

**SELECTED HISTORICAL FINANCIAL INFORMATION**

The selected historical financial information set forth below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and with *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2020 | 2019 | 2018 | 2017 | 2016 |
| | (In thousands, except per share data) | | | | |
| **Consolidated Statement of Operations Information:** | | | | | |
| Revenues: | | | | | |
| Oil | $ 216,419 | $ 399,790 | $ 438,798 | $ 340,010 | $ 268,950 |
| NGLs | 19,101 | 22,373 | 37,127 | 32,257 | 26,429 |
| Natural gas | 99,300 | 106,347 | 99,629 | 108,923 | 100,405 |
| Other | 11,814 | 6,386 | 5,152 | 5,906 | 4,202 |
| Total revenues | 346,634 | 534,896 | 580,706 | 487,096 | 399,986 |
| Operating costs and expenses: | | | | | |
| Lease operating expenses | 162,857 | 184,281 | 153,262 | 143,738 | 152,399 |
| Production taxes | 4,918 | 2,524 | 1,832 | 1,740 | 1,889 |
| Gathering and transportation | 16,029 | 25,950 | 22,382 | 20,441 | 22,928 |
| Depreciation, depletion and amortization | 97,763 | 129,038 | 131,423 | 138,510 | 194,038 |
| Asset retirement obligations accretion | 22,521 | 19,460 | 18,431 | 17,172 | 17,571 |
| Ceiling test write-down of oil and natural gas properties | - | - | - | - | 279,063 |
| General and administrative expenses | 41,745 | 55,107 | 60,147 | 59,744 | 59,740 |
| Derivative (gain) loss | (23,808) | 59,887 | (53,798) | (4,199) | 2,926 |
| Total costs and expenses | 322,025 | 476,247 | 333,679 | 377,146 | 730,554 |
| Operating income (loss) | 24,609 | 58,649 | 247,027 | 109,950 | (330,568) |
| | | | | | |
| Interest expense, net | 61,463 | 59,569 | 48,645 | 45,521 | 84,382 |
| Gain on debt transactions | (47,469) | - | (47,109) | (7,811) | (123,923) |
| Other expense (income), net | 2,978 | 188 | (3,871) | 5,127 | 1,369 |
| (Loss) income before income tax (benefit) expense | 7,637 | (1,108) | 249,362 | 67,113 | (292,396) |
| Income tax (benefit) expense | (30,153) | (75,194) | 535 | (12,569) | (43,376) |
| Net income (loss) | $ 37,790 | $ 74,086 | $ 248,827 | $ 79,682 | $ (249,020) |
| Basic and diluted earnings (loss) per common share | $ 0.26 | $ 0.52 | $ 1.72 | $ 0.56 | $ (2.60) |

## SELECTED HISTORICAL FINANCIAL INFORMATION
(continued)

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2020 | 2019 | 2018 | 2017 | 2016 |
| | | | (In thousands) | | |
| **Consolidated Cash Flow Information:** | | | | | |
| Net cash provided by operating activities | $ 108,509 | $ 232,227 | $ 321,763 | $ 159,408 | $ 14,180 |
| Net cash used in investing activities | (47,616) | (313,814) | (66,385) | (107,107) | (82,396) |
| Net cash provided by (used in) financing activities | (49,600) | 80,727 | (321,143) | (23,479) | 53,038 |

| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2020 | 2019 | 2018 | 2017 | 2016 |
| | | | (In thousands) | | |
| **Consolidated Balance Sheet Information:** | | | | | |
| Cash and cash equivalents | $ 43,726 | $ 32,433 | $ 33,293 | $ 99,058 | $ 70,236 |
| Oil and natural gas properties and other, net (1) | 686,878 | 748,798 | 515,421 | 579,016 | 547,053 |
| Total assets (1) | 940,582 | 1,003,719 | 848,866 | 907,580 | 829,726 |
| Long-term debt (including current portion) | 625,286 | 719,533 | 633,535 | 992,052 | 1,020,727 |
| Shareholders' deficit (1) | (208,286) | (249,365) | (324,796) | (573,508) | (659,037) |

(1) Ceiling test write-downs of $279.1 million was recorded in 2016.

## HISTORICAL RESERVE AND OPERATING INFORMATION

The following tables present summary information regarding our estimated net proved oil, NGLs and natural gas reserves and our historical operating data for the years shown below. Estimated net proved reserves are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December of the respective year in accordance with SEC guidelines. For additional information regarding our estimated proved reserves, please read *Business* under Part I, Item 1 and *Properties* under Part I, Item 2 of this Form 10-K. The selected historical operating data set forth below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and with *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K:

| | December 31, 2020 | 2019 | 2018 | 2017 | 2016 |
|---|---|---|---|---|---|
| **Reserve Data: (1)** | | | | | |
| Estimated net proved reserves | | | | | |
| Oil (MMBbls) | 32.2 | 37.8 | 39.1 | 34.4 | 32.9 |
| NGLs (MMBbls) | 17.4 | 24.5 | 9.8 | 7.8 | 8.2 |
| Natural Gas (Bcf) | 569.3 | 571.1 | 210.5 | 192.2 | 197.8 |
| Total barrel equivalents (MMBoe) | 144.4 | 157.4 | 84.0 | 74.2 | 74.0 |
| Total natural gas equivalents (Bcfe) | 866.5 | 944.5 | 504.1 | 445.3 | 444.0 |
| Proved developed producing (MMBoe) | 120.1 | 122.3 | 53.9 | 54.5 | 47.3 |
| Proved developed non-producing (MMBoe) | 12.1 | 11.5 | 13.1 | 7.7 | 17.4 |
| Total proved developed (MMBoe) | 132.2 | 133.8 | 67.0 | 62.2 | 64.7 |
| Proved undeveloped (MMBoe) | 12.2 | 23.6 | 17.0 | 12.0 | 9.3 |
| Proved developed reserves as % | 91.6% | 85.0% | 79.8% | 83.8% | 87.4% |
| Reserve additions (reductions) (MMBoe): | | | | | |
| Revisions (2) | (1.4) | (3.0) | 21.1 | 9.6 | 13.0 |
| Extensions and discoveries | 0.2 | 1.1 | 2.1 | 5.2 | — |
| Purchases of minerals in place | 3.6 | 90.1 | 3.4 | — | — |
| Sales of minerals in place (3) | — | — | (3.5) | — | — |
| Production | (15.4) | (14.8) | (13.3) | (14.6) | (15.4) |
| Net reserve additions (reductions) | (13.0) | 73.4 | 9.8 | 0.2 | (2.4) |

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

(2) Revisions include changes due to price estimated for reserves held at year-end for each year presented. Revisions in 2020 include estimated price revisions for all proved reserves and incorporate the impact of price change of the purchase of minerals in place from the date of purchase to December 31, 2020.

(3) In 2018, sales of minerals in place primarily relate to conveyance of interest in properties to Monza.

See *Financial Statements and Supplementary Data– Note 20 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

## HISTORICAL RESERVE AND OPERATING INFORMATION
(continued)

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2020 | 2019 | 2018 | 2017 | 2016 |
| **Operating: (1)** | | | | | |
| Net sales: | | | | | |
| Oil (MBbls) | 5,629 | 6,675 | 6,687 | 7,064 | 7,201 |
| NGLs (MBbls) | 1,696 | 1,271 | 1,307 | 1,382 | 1,542 |
| Oil and NGLs (MBbls) | 7,325 | 7,946 | 7,994 | 8,446 | 8,743 |
| Natural gas (MMcf) | 48,384 | 41,310 | 31,991 | 36,754 | 39,731 |
| Total oil equivalent (MBoe) | 15,389 | 14,831 | 13,326 | 14,571 | 15,365 |
| Total natural gas equivalents (MMcfe) | 92,334 | 88,987 | 79,956 | 87,428 | 92,188 |
| Average daily equivalent sales (Boe/day) | 42,046 | 40,634 | 36,510 | 39,921 | 41,980 |
| Average daily equivalent sales (Mcfe/day) | 252,279 | 243,801 | 219,057 | 239,528 | 251,879 |
| Average realized sales prices: | | | | | |
| Oil ($/Bbl) | $ 38.45 | $ 59.89 | $ 65.62 | $ 48.13 | $ 37.35 |
| NGLs ($/Bbl) | 11.26 | 17.60 | 28.40 | 23.35 | 17.14 |
| Oil and NGLs ($/Bbl) | 32.15 | 53.13 | 59.53 | 44.08 | 33.79 |
| Natural gas ($/Mcf) | 2.05 | 2.57 | 3.11 | 2.96 | 2.53 |
| Oil equivalent ($/Boe) | 21.76 | 35.63 | 43.19 | 33.02 | 25.76 |
| Natural gas equivalent ($/Mcfe) | 3.63 | 5.94 | 7.20 | 5.50 | 4.29 |
| Average per Boe ($/Boe): | | | | | |
| Lease operating expenses | $ 10.58 | $ 12.43 | $ 11.50 | $ 9.86 | $ 9.92 |
| Gathering and transportation | 1.04 | 1.75 | 1.68 | 1.40 | 1.49 |
| Production costs | 11.62 | 14.18 | 13.18 | 11.26 | 11.41 |
| Production taxes | 0.32 | 0.17 | 0.14 | 0.12 | 0.12 |
| DD&A (2) | 7.82 | 10.01 | 11.24 | 10.68 | 13.77 |
| General and administrative expenses | 2.71 | 3.72 | 4.51 | 4.10 | 3.89 |
| | $ 22.47 | $ 28.08 | $ 29.07 | $ 26.16 | $ 29.19 |
| Average per Mcfe ($/Mcfe): | | | | | |
| Lease operating expenses | $ 1.76 | $ 2.07 | $ 2.30 | $ 1.75 | $ 1.56 |
| Gathering and transportation | 0.17 | 0.29 | 0.32 | 0.26 | 0.22 |
| Production costs | 1.93 | 2.36 | 2.62 | 2.01 | 1.78 |
| Production taxes | 0.05 | 0.03 | 0.03 | 0.02 | 0.02 |
| DD&A (2) | 1.30 | 1.67 | 1.86 | 1.71 | 1.69 |
| General and administrative expenses | 0.45 | 0.62 | 0.69 | 0.69 | 0.65 |
| | $ 3.73 | $ 4.68 | $ 5.20 | $ 4.43 | $ 4.14 |
| Wells drilled (gross) (3) | — | 6 | 6 | 5 | 1 |
| Productive wells drilled (gross) (3) | — | 6 | 6 | 4 | 1 |

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

(2) DD&A - depreciation, depletion, amortization and accretion

(3) Wells drilled in the above table are all offshore wells.

**Item 7.** ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis 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 Form 10-K. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in *Risk Factors* under Part I, Item 1A in this Form 10-K.

## 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 (41 producing fields and 2 capable of producing). We currently have under lease approximately 737,000 gross acres (506,000 net acres) spanning across the OCS off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 527,000 gross acres on the conventional shelf and approximately 210,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 146 offshore structures, 105 of which are located in fields that we operate. We currently own interest in 213 productive wells, 152 of which we operate. Our interest in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. and our wholly-owned subsidiary, W & T Energy VI, LLC, a Delaware limited liability company and through our proportionately consolidated interest in Monza, as described in more detail in *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K.

### 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 2020, average realized commodity prices decreased from those we experienced during 2019 and 2018. Our margins in 2020 decreased from 2019 primarily due to lower average realized commodity prices, partially offset by lower operating expenses as a result of our cost-cutting efforts in 2020. 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 increased 3.8% in 2020 from the prior year. Our proved reserves decreased by 13.0 MMBoe in 2020, primarily due to the significant decline in commodity prices in 2020 as compared to 2019. During 2020, we drilled one additional well which we expect to be completed in 2021.

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

*Acquisition of the Mobile Bay Properties.* In August 2019, we acquired the Mobile Bay Properties with the purchase of Exxon's 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. After taking into account customary closing adjustments and an effective date of January 1, 2019, cash consideration was $169.8 million. See *Financial Statements and Supplementary Data* – Note 5 – Acquisitions and Divestures under Part II, Item 8 in this Form 10-K for a full description of the acquisition.

As of December 31, 2020, the Mobile Bay Properties had approximately 79.3 MMBoe of net proved reserves, of which 98% were proved developed producing reserves consisting primarily of natural gas and NGLs with 15% of the proved net reserves from liquids on an MMBoe basis, based on SEC pricing methodology. For 2020, the average production of the Mobile Bay Properties was approximately 15,400 net Boe per day. The properties include working interests in nine Gulf of Mexico offshore producing fields and an onshore treatment facility that are adjacent to existing properties owned and operated by us. With this purchase, we became the largest operator in the area. The Mobile Bay Properties accounted for 37% of our production measured on an MMBoe basis in 2020.

*Income tax benefit (expense).* Deferred tax assets are recorded related to net operating losses ("NOL") 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 NOLs 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 reduction of the valuation allowance in recent years has resulted in increases to net income that may not be indicative of future periods. See *Financial Statements and Supplementary Data – Note 12 – Income Taxes* under Part II, Item 8 in this Form 10-K for additional information.

**Known Trends and Uncertainties**

*COVID-19.* Due to circumstances related to the outbreak of COVID-19, various measures have been taken by federal, state and local governments to reduce the rate of spread of COVID-19. These measures and other factors have resulted in a decrease of general economic activity and a corresponding decrease in global and domestic energy demand impacting commodity pricing. In addition, actions by the Organization of Petroleum Exporting Countries and other high oil exporting countries like Russia ("OPEC+") have negatively impacted crude oil prices in early 2020. These rapid and unprecedented events pushed crude oil storage near capacity and drove prices down significantly in the second quarter of 2020. These events have been the primary cause of the significant supply-and-demand imbalance for oil, significantly lowering oil pricing in 2020 compared to the prior year. Through February 2021, COVID-19 outbreak levels continued and, in some cases, increased in some areas of the United States. Should these conditions continue in future periods, they could constrain our ability to store and move production to downstream markets, delay or curtail development activity or temporarily shut-in production, any or all of which could further reduce our cash flow.

*Volatility in Oil, NGL and Natural Gas Prices.* Our realized sales prices received for our crude oil, NGLs and natural gas production are affected by not only domestic production activities and political issues, but more importantly, international events, including both geopolitical and economic events. During 2020, crude oil, NGLs and natural gas average realized prices were below 2019 realized prices, decreasing 35.8%, 36.0% and 20.1%, respectively.

Prolonged period of weak commodity prices like we experienced during 2020 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.

Selected issues and data points related to crude oil, NGLs and natural gas markets are described below.

As reported by the U.S. Energy Information Administration ("EIA") in their Short-Term Energy Outlook issued in February 2021 ("STEO"), worldwide production of petroleum and other liquids was estimated to have decreased by 6.4% in 2020 over the prior year, as compared to no year-over-year production growth for 2019 and a 3.1% increase in year-over-year production growth for 2018. The decrease was due primarily to lower levels of drilling and production curtailments by OPEC and other producers in response to lower oil prices. Consumption for 2020 decreased 8.4% over 2019, largely due to reduced economic activity from the COVID-19 pandemic.

EIA's forecasts for production, consumption, crude oil prices and natural gas prices for 2021 remain subject to heightened levels of uncertainty because responses to COVID-19 continue to evolve. The EIA forecasts worldwide production of petroleum and other liquids year-over-year increases for 2021 and 2022 to be 3.3% and 3.6%, respectively. The expected increase is due primarily to increases in drilling activity in the U.S. in recent months. Consumption for 2021 and 2022 is estimated to increase year-over-year by 5.8% and 3.6%, respectively, as a result of the roll-out of COVID-19 vaccines. According to EIA, U.S. crude oil production (excluding other petroleum liquids) decreased 7.6% in 2020 over 2019, and is expected to decrease year-over-year in 2021 by 2.6% and increase year-over-year in 2022 by 4.6%. For the U.S., net imports of crude oil in the U.S. fell by 28.9% in 2020 compared to 2019 and are expected to increase by 36.2% in 2021 from 2020.

The two primary benchmarks for our average realized crude oil sales prices are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $39.17 per barrel for 2020, down from $56.98 barrel for 2019 (31.3% decrease). During January and February of 2021, WTI crude oil prices have ranged from as low as $47.47 per barrel to as high as $63.43 per barrel, Brent crude oil prices averaged $41.69 per barrel for 2020, down from $64.28 per barrel for 2019 (35.1% decrease). During January and February of 2021, Brent crude oil prices have ranged from as low as $50.37 per barrel to as high as $66.85 per barrel, The EIA projects average crude oil prices for WTI to increase approximately $11.00 per barrel in 2021 compared to 2020, and increase in 2022 by approximately $1.00 per barrel. The EIA projects average Brent crude oil prices to increase approximately $11.00 per barrel in 2021 compared to 2020, and to increase approximately $2.00 per barrel in 2022.

For 2020, our average realized crude oil sales price was $ 38.45 per barrel. 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, volume weighting (collectively referred to as differentials) and other factors. Crude oil quality adjustments can vary significantly by field. 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 characterized as Poseidon, Mars, Thunder horse, Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS") and others. 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. 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 2020 declined on average by approximately $3.40 - $4.70 per barrel compared to 2019 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.

During 2020, our average realized NGLs sales price per barrel decreased by 36.0% compared to 2019. Two major components of our NGLs, ethane and propane, typically make up approximately 70% of an average NGL barrel. During 2020, average prices for domestic ethane decreased by 8% and average domestic propane prices decreased by 13% from 2019 as measured using a price index for Mount Belvieu. The changes in the average price for other domestic NGLs components in 2020 ranged from a decrease of 10% to 38% year-over-year. Per EIA, production of ethane increased 10% in 2020 compared to 2019 and is expected to increase year-over-year by 9% and 15% for 2021 and 2022, respectively. Propane production increased 6% in 2020 compared to 2019 and is expected to increase year-over-year by 1% for 2021 and decrease 1% for 2022. Ethane and propane inventories increased 10% and decreased 14%, respectively as of December 31, 2020 compared to December 31, 2019. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Propane usage is affected by weather as it is used for house heating fuel in certain areas and for crop drying, along with other uses. Heating degree days decreased approximately 9% in 2020 compared to 2019.

During 2020, our average realized natural gas sales price decreased 20.1% compared to 2019. According to data from EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 20.7% lower in 2020 compared to 2019. During January and February of 2021, spot prices for natural gas have ranged from as low as $2.54 per Mcf to as high as $24.74 per Mcf, Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. Natural gas inventories at the end of 2020 were 5.2% higher than at the end of 2019. EIA projects natural gas supply to be slightly less than consumption in 2021 and forecasts Henry Hub spot prices to increase by 45% year-over-year to $3.07 per Mcf.

EIA reports that electrical power generation sourced by natural gas consumption increased to 39% in 2020 compared to 37% in 2019 and forecasts this percentage to remain at approximately the same level in 2021 and 2022. The percentage of electrical power generation sourced from coal fell in 2020 to 20% compared to 24% 2019 and is expected to remain at approximately the same levels in 2021 and 2022. The percentage of electrical power sourced from renewable sources, such as hydropower and wind, increased to 20% in 2020 as compared to 17.4% in 2019 and is forecast to exceed 22% by 2022.

According to Baker Hughes, as of December 31, 2020, there were 351 working rigs drilling for oil and natural gas in the U.S. 805 working rigs as of December 31, 2019. The oil rig counts at the end of December 2020 and December 2019 were 267 and 677, respectively. The U.S. natural gas rig counts at the end of December 2020 and December 2019 were 83 and 125, respectively. In the Gulf of Mexico, the number of working rigs was 17 rigs (17 oil and no natural gas rigs) at the end of December 2020 and 23 rigs (22 oil and one natural gas rigs) at the end of December 2019.

*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.

*Lease Operating Expense.* Our lease operating expenses include the expense of operating 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 costs, facility repairs and maintenance, workover costs, insurance premiums, and gathering and transportation costs. Our operating costs depend in part on the type of commodity produced, the level of workover activity and the geographical location of the properties. Workover costs can vary significantly from year to year depending on the level of activity (either required or desired) and type of equipment used. In those instances where a drilling rig is required as opposed to some other type of intervention vessel or equipment, the costs tend to be higher and require more time.

*Hurricane and Tropical Storm Events.* Our offshore operations are exposed to potential damage from hurricanes and we normally obtain insurance to reduce, but not totally mitigate, our financial exposure risk. See *Liquidity and Capital Resources – Insurance Coverage* under this Item 7 in this Form 10-K for additional information.

*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–Regulation–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 2020 or 2019, we have not had to post collateral for sureties. 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.

*Paycheck Protection Program ("PPP").* 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. As of the date of this filing, we have not received a response from the SBA, regarding the SBA's acceptance of our application. Management believes the Company has met all of the requirements under the PPP and will not be required to repay any portion of the grant.

**Results of Operations**

***Year Ended December 31, 2020 Compared to Year Ended December 31, 2019***

*Revenues*. Total revenues decreased $ 188.3 million, or 35.2%, to $ 346.6 million in 2020 as compared to $534.9 million in 2019. Oil revenues decreased $ 183.4 million, or 45.9%, NGLs revenues decreased $ 3.3 million, or 14.6%, natural gas revenues decreased $ 7.0 million, or 6.6%, and other revenues increased $ 5.4 million. The oil revenue decrease was attributable to a 35.8% per barrel decrease in the average realized sales price to $ 38.45 per barrel in 2020 from $59.89 per barrel in 2019 and a 15.7% decrease in sales volumes. The NGLs revenue decrease was attributable to a 36.0% decrease in the average realized sales price to $ 11.26 per barrel in 2020 from $17.60 per barrel in 2019, offset by an increase of 33.4% in sales volumes. The decrease in natural gas revenue was attributable to a 20.1% decrease in the average realized natural gas sales price to $ 2.05 per Mcf in 2020 from $2.57 per Mcf in 2019, partially offset by a 17.1% increase in sales volumes. Overall, prices decreased 38.9% on a per Boe basis and production increased 3.5% on a per Boe per day basis. The largest production increases for 2020 compared to 2019 were from our acquired interest in the Mobile Bay Properties and at Magnolia. Partially offsetting the increases were production decreases related to natural production declines and production deferral. Production for 2020 was also negatively impacted by a record number of named storms, maintenance, well issues and pipeline outages that collectively resulted in deferred production of 2.8 MMBoe, compared to 2.1 MMBoe in 2019.

Revenues from oil and liquids as a percent of our total revenues were 67.9% for 2020 compared to 78.9% for 2019. The average realized sales price per barrel of NGLs as a percent of average realized price of crude oil per barrel decreased to 29.3% for 2020 compared to 29.4% for 2019.

*Lease operating expenses.* Lease operating expenses, which include base lease operating expenses, insura nce premiums, workovers, and facilities maintenance expenses, decreased $ 21.4 million, or 11.63 %, to $ 162.9 million in 2020 compared to $184.3 million in 2019. On a per Boe basis, lease operating expenses decreased to $10.58 per Boe during 2020 compared to $12.43 per Boe during 2019. On a component basis, base lease operating expenses decreased $7.7 million, workover expenses decreased $12.0 million and facilities maintenance expenses decreased $6.8 million. These decreases were partially offset by an increase in hurricane repair expenses of $4.7 million and an increase of $0.3 million in insurance premiums.

Base lease operating expenses decreased primarily due to reduced expenses of $24.1 million from shutting in certain fields; and credits to expense due to prior period royalty adjustments of $6.0 million. These decreases were partially offset by $13.4 million increases due to the acquisitions of interests in the Mobile Bay Properties in August 2019 and December 2020, and a $9 million increase related to the acquisition of Garden Banks 783/784 ("Magnolia") field in December 2019. The decreases in workover expense and facility maintenance were due to fewer projects undertaken in 2020 as compared to 2019.

*Production taxes*. Production taxes were $ 4.9 million in 2020, an increase of $ 2.4 million as compared to 2019, due to the acquisition of the Mobile Bay Properties. Most of our production is from federal waters where no production taxes are imposed. The Mobile Bay Properties and our Fairway field, both of which are predominantly in state waters, are subject to production taxes.

*Gathering and transportation costs.* Gathering and transportation costs decreased to $ 16.0 million, or 38.2%, in 2020 compared to $26.0 million in 2019. Costs decreased from the prior year primarily due to lower transportation rates as well as lower volumes in 2020 for the majority of our fields (specifically, lower oil volumes) related to downtime events, partially offset by a full year impact of gathering and transportation costs associated with the Mobile Bay and Magnolia acquisitions.

*Depreciation, depletion, amortization and accretion.* DD&A, which includes accretion for ARO, decreased to $ 7.82 per Boe in 2020 from $10.01 per Boe in 2019. On a nominal basis, DD&A decreased to $ 120.3 million ( 19.0%) in 2020 from $148.5 million in 2019. The year-over-year decline in the DD&A rate per Boe was driven by the large reserve additions relative to the purchase price associated with the acquisitions of the Mobile Bay and Magnolia assets. Other factors affecting the DD&A rate are capital expenditures and changes in future development costs on remaining reserves.

*General and administrative expenses ("G&A").* For 2020, G&A expenses were $41.8 million compared to $55.1 million in 2019. The decrease in 2020 G&A expense compared to 2019 was driven primarily by credits from W&T's PPP funds in 2020, a decrease in share based compensation expense and cash incentive compensation expense which did not occur in 2020, and a decrease in legal expense to adjust for the final settlement of BSEE Civil penalties. On a unit of production basis, G&A was $2.71 per Boe in 2020 compared to $3.72 per Boe in 2019.

*Derivative loss (gain).* For 2020, a $ 23.8 million derivative gain was recorded for crude oil and natural gas derivative contracts. We entered into derivative contracts for crude oil during 2020 for both certain crude oil and natural gas derivative contracts. For 2019, a $59.9 million derivative loss was recorded for crude oil and natural gas derivative contracts. The loss in 2019 and gain in 2020 are primarily due to crude oil prices rising in the latter months of 2019 and subsequently falling in late 2020 relative to the year end 2019 crude oil price, which impacted future prices used to value the derivative contracts in 2019 and 2020, respectively. See *Financial Statements and Supplementary Data – Note 9 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

*Interest expense, net*. Interest expense, net, was $ 61.5 million in 2020, increasing 4.2% from $59.6 million in 2019. The increase is primarily due to lower interest income between the two periods, partially offset by a lower principal balance of the Senior Second Lien Notes. Interest income decreased to $0.6 million in 2020 compared to $7.7 million in 2019, primarily due to interest income related to the income tax refunds, Apache and RIK matters in 2019, each matter containing an element of interest income. *See Financial Statements and Supplementary Data - Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information on our debt. *See Financial Statements and Supplementary Data - Note 17 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information on the Apache and RIK matters.

*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 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information.

*Other (income) expense, net*. During 2020, other expense, net, was $2.9 million, compared to $0.2 million of other income, net, for 2019. 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. For 2019, the amount consists primarily of federal royalty obligation reductions claimed in 2019 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.

*Income tax benefit (expense).* Our income tax benefit for 2020 and 2019 was $30.2 million and $75.2 million, respectively. For 2020, 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. For 2019, our income tax benefit was primarily due to reversals of previously recorded valuation allowances and for the reversal of a liability related to an uncertain tax position that was effectively settled with the Internal Revenue Service ("IRS") during the year. Our annual effective tax rates for 2020 and 2019 were not meaningful and differ from the federal statutory rates of 21% primarily due to valuation allowance adjustments recorded for our deferred tax assets in both periods. During 2020, we recorded a net decrease to the valuation allowance of $32.1 million related to federal and state deferred tax assets. During 2019, we recorded a net decrease to the valuation allowance of $63.3 million related to federal and state deferred tax assets and a reversal of an uncertain tax position resulting in a non-cash tax benefit of $11.5 million. Deferred tax assets are recorded related to net operating losses ("NOL") 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 NOLs 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.

***Year Ended December 31, 2019 Compared to Year Ended December 31, 2018***

For year-to-year comparisons between 2019 and 2018 that are not included in this Annual Report on Form 10-K, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

**Liquidity and Capital Resources**

The primary sources of our liquidity are cash from operating activities and borrowings under our Credit Agreement. As of December 31, 2020, we had $43.7 million of available cash and $130.6 million available under our Credit Agreement, based on a borrowing base of $215.0 million. The borrowing base was further reduced in January 2021 from $215.0 million to $190 million, or a $25.0 million reduction, as a result of the second semi-annual redetermination of 2020. See discussion in *Credit Agreement* below.

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.

We believe that we will have adequate liquidity from cash flow from operations to fund our capital expenditure plans for 2021, fund our ARO spending for 2021 and fulfill our various other obligations.  Availability under our Credit Agreement as of December 31, 2020 was $130.6 million.  Our preliminary capital expenditure budget for 2021 has been established in the range of $30.0 million to $60.0 million, which includes our share of the Joint Venture Drilling Program, and excludes acquisitions.  In our view of the outlook for 2021, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2021 and beyond while providing liquidity to make strategic acquisitions.  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.

*Joint Venture Drilling Program.* To provide additional financial flexibility, we created the Joint Venture Drilling Program with private investors during 2018 and drilled and completed nine wells by the end of 2019.  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, and we expect to complete this well in 2021. See *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K for additional information on the Joint Venture Drilling Program.

*Credit Agreement*. As of December 31, 2020, we had $80.0 million of borrowings outstanding under the Credit Agreement and $4.4 million of letters of credit issued under the Credit Agreement.  During 2020, borrowings under the Credit Agreement ranged from $105.0 million down to $80.0 million.  Subsequent to the redetermination, availability under our Credit Agreement as of December 31, 2020 was $130.6 million.  Availability under our Credit Agreement is subject to a semi-annual redetermination of our borrowing base to occur around May 15 and November 14 each calendar year, and certain additional redeterminations that may be requested at the discretion of either the lenders or the Company.  Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our Credit Agreement.  As of December 31, 2020, the borrowing base was $215.0 million.  Additionally, in January 2021, our borrowing base was reduced from $215 million to $190 million as a result of the second semi-annual redetermination for 2020.

We currently have six lenders within the revolving bank credit facility, with commitments ranging from 10% to 25% of the current borrowing base.  While we have not experienced, nor do we anticipate, any difficulties in obtaining funding from any of these lenders at this time, any lack of or delay in funding by members of our banking group could negatively impact our liquidity position.  The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the Credit Agreement.  We were in compliance with all applicable covenants of the Credit Agreement and the other debt instruments as of December 31, 2020.

On January 6, 2021, we entered into a Waiver, Consent to Second Amendment to Intercreditor Agreement and Fifth Amendment to Sixth Amended and Restated Credit Agreement (the "Fifth Amendment") dated as of January 6, 2021, among the Company, certain of its guarantor subsidiaries, Toronto Dominion (Texas) LLC, individually and as administrative agent, and certain of the Company's lenders and other parties thereto. The Fifth Amendment includes the following changes, among other things, to the Credit Agreement:

- Reducing the borrowing base under the Credit Agreement from $215.0 million to $190.0 million.
- Amends and waives certain hedging requirements for projected natural gas production volumes of the Company to the extent that certain identified existing hedge contracts may cause non-compliance with minimum swap requirements for hedged volumes for any test date related to any calendar quarterly period ended on or before December 31, 2022 and requires that all natural gas hedge contracts entered into after December 13, 2020 until the December 31, 2022 test date (or such earlier date as provided in the Fifth Amendment) shall be in the form of swaps and not collars or puts until swaps represent at least 50% of natural gas hedge positions for all months required to be hedged by the Credit Agreement.
- Establishes procedures for the Company to propose additional hedge counterparties and directs the administrative agent to enter into hedge intercreditor agreements with one or more hedge counterparties from time to time.
- Establishes a customary anti-cash hoarding prepayment requirement in the event the cash balances of the Company exceed $25.0 million (subject to customary adjustments) at the end of the calendar month.

Under the Fifth Amendment, the lenders under the Credit Agreement have also consented to certain conforming amendments necessitated by the Fifth Amendment proposed to be made to that certain Intercreditor Agreement among Toronto Dominion (Texas) LLC, as Original Priority Lien Agent and Wilmington Trust, National Association, as Second Lien Trustee and as Second Lien Collateral Agent.

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

*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 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. As of December 31, 2020, we had outstanding open derivatives for crude oil and natural gas. See *Financial Statements and Supplementary Data - Note 9 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

*Cash Flows*. Net cash provided by operating activities for 2020 was $108.5 million, decreasing $123.7 million, or 53.3%, from 2019. The change between periods is primarily due to lower realized prices for crude oil, NGLs and natural gas, and working capital changes, partially offset by increased volumes, increased derivative settlements, lower spending for ARO activities, and lower income tax refunds. Our combined average realized sales price per Boe decreased 38.9% in 2020, which caused total revenues to decrease $213.6 million, partially offset by increases of 3.5% in overall production volumes which caused revenues to increase by $ 19.9 million.

Other items affecting operating cash flows for 2020 were: ARO settlements of $3.3 million, which decreased from $11.4 million in 2019; cash advances from joint venture partners increased $ 2.0 million during 2020 compared to a decrease of $15.3 million during 2019; derivative cash receipts, net, were $45.2 million in 2020 compared to derivative cash receipts, net, of $13.9 million in 2019; and income tax refunds were $2.0 million in 2020 compared to income tax refunds of $52.2 million in 2019.

Net cash used in investing activities during 2020 and 2019 was $47.6 million and $313.8 million, respectively, which represents our acquisitions and investments in oil and gas properties and equipment. Investments in oil and natural gas properties 2020 were $44.2 million, which was a decrease of $81.5 million from 2019. The majority of our capital expenditures for 2020 related to investments on the conventional shelf in the Gulf of Mexico and, to a lesser extent, in the deepwater of the Gulf of Mexico. 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. During 2019, the acquisition of property interest of $188.0 million was primarily related to the acquisition of the Mobile Bay Properties and, to a lesser extent, the acquisition of the Magnolia Field. There were no asset sales of significance in 2020 or 2019.

Net cash used by financing activities for 2020 was $49.6 million and net cash provided by financing activities for 2019 was $80.7 million. The 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 net cash provided by financing activities in 2019 was from borrowings under the Credit Agreement to fund the acquisition of the Mobile Bay Properties, of which a portion was paid down by December 31, 2019. The purchase of the Senior Second Lien Notes are disclosed in *Financial Statements and Supplementary Data - Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K.

*Capital expenditures.* Our preliminary capital expenditure budget for 2021 has been established in the range of $30.0 million to $60.0 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. Some of our expenditures incurred during 2019 impacted our production for 2019, but most of the impact is expected to occur in 2020 and beyond. In addition, we spent $3.3 million in 2020 and $11.4 million in 2019 for ARO and plan to spend in the range of $17.0 million to $21.0 million in 2021 for ARO.

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, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| | | **(In thousands)** | |
| Exploration (1) | $ 1,837 | $ 17,121 | $ 49,890 |
| Development (1) | 11,109 | 107,662 | 47,224 |
| Acquisitions of interest - Mobile Bay (2) | 1,865 | 170,689 | — |
| Acquisition of interest – Magnolia Field (3) | 831 | 15,950 | — |
| Acquisition of interest - other | 222 | — | — |
| Acquisition of interest – Heidelberg Field (4) | — | — | 16,782 |
| Reimbursement from Monza for 2017 expenditures | — | — | (14,075) |
| Seismic and other | 4,686 | 14,412 | 7,702 |
| Acquisitions and investments in oil and gas property/equipment – accrual basis | $ 20,550 | $ 325,834 | $ 107,523 |

(1) Reported geographically in the subsequent table.
(2) Acquired in September 2019.
(3) Acquired in December 2019.
(4) Acquired in April 2018.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| | | **(In thousands)** | |
| Conventional shelf | $ 10,247 | $ 39,093 | $ 69,354 |
| Deepwater | 2,699 | 85,690 | 27,760 |
| Exploration and development capital expenditures – accrual basis | $ 12,946 | $ 124,783 | $ 97,114 |

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 | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Offshore – gross wells drilled: | | | |
| Conventional shelf | — | 3 | 3 |
| Deepwater | — | 3 | 3 |
| Wells operated by W&T | — | 5 | 5 |

We had a 100% success rate in 2019 and 2018. During 2020, we drilled one well, which we expect to be completed in 2021. All of these wells are in the Joint Venture Drilling Program.

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 39 leases for approximately $6.9 million from the BOEM in the Federal Offshore Lease Sales. Per year, we acquired 4 leases ($1.2 million), 17 leases ($3.8 million), and 17 leases ($1.9 million) in the years 2020, 2019, and 2018, respectively.

*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. As previously discussed, in 2018 we sold our overriding interests in the Yellow Rose field for $56.6 million after adjustments. In 2020 and 2019, there were no property sales of significance. See *Financial Statements and Supplementary Data – Note 5 –Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information on this divestiture.

*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, 2020 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 $30.0 million. 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, 2020. 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, 2020 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 $150.0 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 $10.4 million for the May/June 2020 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.

*Liquidity for 2021.* We believe that we will have adequate liquidity from cash flow from operations to fund our capital expenditure plans for 2021, fund our ARO spending for 2021 and fulfill our various other obligations. Availability under our Credit Agreement as of December 31, 2020 was $130.6 million. Our preliminary capital expenditure budget for 2021 has been established in the range of $30.0 million to $60.0 million, which includes our share of the Joint Venture Drilling Program and excludes acquisitions. In our view of the outlook for 2021, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2021 and beyond. 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.

*Income taxes*. As of December 31, 2020, we have current income taxes payable of $0.2 million. During 2020, we received refunds of $2.0 million and interest income of $0.1 million primarily related to our NOL claim for the year 2017 that was carried back to prior years. The claim was made pursuant to Internal Revenue Code ("IRC") rules for specified liability losses, which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. Under the Tax Cuts and Jobs Act ("TJCA"), effective in 2017, NOLs including those related to specified liability losses can no longer be carried back for tax years beginning after 2017. For 2020, we do not expect to make any significant income tax payments.

*Dividends*. During 2020, 2019 and 2018, we did not pay any dividends and a suspension of dividends remains in effect.

*Asset retirement obligations*. Annually we review and revise our ARO estimates. Our ARO at December 31, 2020 and 2019 were $392.7 million and $355.6 million, respectively, recorded using discounted values. Our estimate of ARO spending in 2021 is $17.0 million to $21.0 million. During 2020 and 2019, 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 6 – Asset Retirement Obligations* under Part II, Item 8 in this Form 10-K for additional information regarding our ARO.

*Discretionary Bonus to Employees in 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 $7.6 million, payable in equal installments on March 15, 2021 and April 15, 2021, subject to employment on those dates.

*Contractual obligations*. At December 31, 2020, we did not have any capital leases. The following table summarizes our significant contractual obligations by maturity as of December 31, 2020 (in millions):

| | Payments Due by Period as of December 31, 2020 | | | | |
|---|---|---|---|---|---|
| | **Total** | **Less than One Year** | **One to Three Years** | **Three to Five Years** | **More Than Five Years** |
| Long-term debt – principal | $ 632.5 | $ — | $ 632.5 | $ — | $ — |
| Long-term debt – interest (1) | 165.4 | 57.7 | 107.7 | — | — |
| Operating leases | 23.6 | 0.3 | 2.8 | 3.5 | 17.0 |
| Asset retirement obligations (2) | 392.7 | 17.2 | 58.3 | 56.1 | 261.1 |
| Other liabilities and commitments (3) | 94.7 | 8.4 | 14.3 | 12.8 | 59.2 |
| Total | $ 1,308.9 | $ 83.6 | $ 815.6 | $ 72.4 | $ 337.3 |

(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, 2020 and assumes no change in this interest rate in future periods. In addition, a commitment fee of 0.5% was applied on the available balance as of December 31, 2020 and fees related to letters of credit were estimated at the rate incurred on December 31, 2020; (b) Interest payments on the Senior Second Lien Notes were calculated per the terms of the notes.

(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, 2020 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, 2020, we had approximately $400.6 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.

**Inflation and Seasonality**

*Inflation*. For 2020, our realized prices for crude oil decreased 35.8%, NGLs decreased 36.0% and natural gas decreased 20.1% from 2019. These are discussed in the *Overview* section above. Historically, our costs for goods and services have moved directionally with the price of crude oil, NGLs and natural gas, as these commodities affect the demand for these goods and services. Operating costs directly related to production (lease operating expenses, production taxes and gathering and transportation) measured on a $/Boe basis decreased by 16.8% in 2020 compared to 2019 and increased by 7.7% in 2019 compared to 2018. These operating costs related to production are substantially impacted by factors other than national general rates of inflation or deflation, such as workovers, facility repairs, production handling fees for certain fields (recorded as credits to expense), production levels, hurricanes, changes in regulations, types of commodities produced and the level of oil and gas activity in the Gulf of Mexico.

**Critical Accounting Policies**

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.

*Full-cost accounting.* We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Capitalization of geological and geophysical costs, certain employee costs and G&A expenses related to these activities is permitted. We amortize our investment in oil and natural gas properties, capitalized ARO and future development costs (including ARO of wells to be drilled) through DD&A, using the units-of-production method. The units-of-production method uses reserve information in its calculations. 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.

Our financial position and results of operations may have been significantly different had we used the successful-efforts method of accounting for our oil and natural gas investments. GAAP allows successful-efforts accounting as an alternative method to full-cost accounting. The primary difference between the two methods is in the treatment of exploration costs, including geological and geophysical costs, and in the resulting computation of DD&A. Under the full-cost method, which we follow, exploratory costs are capitalized, while under successful-efforts, the cost associated with unsuccessful exploration activities and all geological and geophysical costs are expensed. In following the full-cost method, we calculate DD&A based on a single pool for all of our oil and natural gas properties, while the successful-efforts method utilizes cost centers represented by individual properties, fields or reserves. Typically, the application of the full-cost method of accounting for oil and natural gas properties results in higher capitalized costs and higher DD&A rates, compared to similar companies applying the successful efforts method of accounting.

DD&A can be affected by several factors other than production. The rate computation 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 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 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. Any write downs occurring as a result of the ceiling test impairment are not recoverable or reversible in future periods. We did not have any ceiling test impairments in 2020, 2019 or 2018, but did have ceiling test impairment in 2016. Ceiling test impairments in future periods are highly dependent on commodity prices, and also are impacted by other factors and events. For the effect of lower commodity prices on revenues and earnings, see *Quantitative and Qualitative Disclosures on Market Risks* under Part II, Item 7A in this Form 10-K for additional information.

*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. We make changes to DD&A rates and impairment calculations in the same period that changes to our reserve estimates are made. Our proved reserve information as of December 31, 2020 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*. We have significant obligations to plug and abandon all 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 the future restoration and removal cost is difficult and requires us to make estimates and judgments because the removal obligations may be many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. Pursuant to GAAP, we are required to record a separate liability for the discounted present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet.

Inherent in the present value calculation of our liability are numerous estimates and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and changes in the legal, regulatory, environmental and political environments. Revisions to these estimates impact the value of our abandonment liability, our oil and natural gas property balance and our DD&A rates.

*Income taxes*. GAAP requires the use of the liability method of computing deferred income taxes, whereby deferred income taxes are recognized for the future tax consequences of the differences between the tax basis of assets and liabilities and the carrying amount in our financial statements. 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 are expected to be recovered or settled. Because our tax returns are filed after the financial statements are prepared, estimates are required in recording tax assets and liabilities. We record adjustments to reflect actual taxes paid in the period we complete our tax returns. 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. 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.

*Paycheck Protection Program.* As there is no definitive guidance under U.S. GAAP, we have applied the guidance under International Accounting Standards 20, *Accounting for Government Grants and Disclosure of Government Assistance* ("IAS 20") and have elected to follow the income approach under IAS 20 and recognize earnings as funds are applied to covered expenses and classify the application of the funds as a reduction of the related expense in the Consolidated Statement of Operations. As a result, we have reduced expenses during the year ended December 31, 2020 and classified expense reductions consistent with our PPP fund application request.

## 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 from time to time to reduce the risk of fluctuations in commodity prices and expect to use these instruments in the future. We entered into derivative contracts for crude oil and natural gas during 2020 and had open derivative contracts as of December 31, 2020. We do not designate our commodity derivative contracts as hedging instruments. 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.* Our revenues, profitability and future rate of growth substantially depend upon market prices for crude oil, NGLs and natural gas, which fluctuate widely. Crude oil, NGLs and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. For example, assuming a 10% decline in our average realized oil, NGLs and natural gas sales prices in 2020 and assuming no other items had changed, our income before income tax would have decreased by approximately $35 million in 2020. If costs and expenses of operating our properties had increased by 10% in 2020, our income before income tax would have decreased by approximately $18 million in 2020. These amounts would be representative of the effect on operating cash flows under these price and cost change assumptions.

*Interest rate risk.* As of December 31, 2020, we had $80.0 million 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 ranges from 2.75% to 3.75% depending on the amount outstanding. In 2020, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have increased $0.9 million during 2020. We did not have any derivative contracts related to interest rates as of December 31, 2020.

**Item 8.** ***Financial Statements and Supplementary Data***

**W&T OFFSHORE, INC. AND SUBSIDIARIES**
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## 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, 2020 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, 2020 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 Board of Directors and Shareholders 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, 2020, 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, 2020, 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, 2020 and 2019, 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, 2020, and the related notes and our report dated March 4, 2021 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 4, 2021

## Report of Independent Registered Public Accounting Firm

**The Board of Directors and Shareholders 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, 2020 and 2019, 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, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 4, 2021 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, 2020, the net book value of the Company's oil and natural gas properties was $687 million, and depreciation, depletion and amortization ("DD&A") expense was $98 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, 2020.<br><br>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.<br><br>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, 2020, the asset retirement obligation (ARO) balance totaled $393 million. As further described in Notes 1 and 6, 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.<br><br>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.<br><br>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. |

/s/ Ernst & Young LLP

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

Houston, Texas
March 4, 2021

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

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 43,726 | $ 32,433 |
| Receivables: | | |
| Oil and natural gas sales | 38,830 | 57,367 |
| Joint interest, net | 10,840 | 19,400 |
| Income taxes | — | 1,861 |
| Total receivables | 49,670 | 78,628 |
| Prepaid expenses and other assets (Note 1) | 13,832 | 30,691 |
| Total current assets | 107,228 | 141,752 |
| | | |
| Oil and natural gas properties and other, net – at cost: (Note 1) | 686,878 | 748,798 |
| | | |
| Restricted deposits for asset retirement obligations | 29,675 | 15,806 |
| Deferred income taxes | 94,331 | 63,916 |
| Other assets (Note 1) | 22,470 | 33,447 |
| Total assets | $ 940,582 | $ 1,003,719 |
| **Liabilities and Shareholders' Deficit** | | |
| Current liabilities: | | |
| Accounts payable | $ 48,612 | $ 102,344 |
| Undistributed oil and natural gas proceeds | 19,167 | 29,450 |
| Advances from joint interest partners | — | 5,279 |
| Asset retirement obligations | 17,188 | 21,991 |
| Accrued liabilities (Note 1) | 29,880 | 30,896 |
| Income tax payable | 153 | — |
| Total current liabilities | 115,000 | 189,960 |
| Long-term debt: (Note 2) | | |
| Principal | 632,460 | 730,000 |
| Carrying value adjustments | (7,174) | (10,467) |
| Long-term debt – carrying value | 625,286 | 719,533 |
| | | |
| Asset retirement obligations, less current portion | 375,516 | 333,603 |
| Other liabilities (Note 1) | 32,938 | 9,988 |
| Deferred income taxes | 128 | — |
| Commitments and contingencies (Note 17) | — | — |
| Shareholders' deficit: | | |
| Preferred stock, $0.00001 par value; 20,000 shares authorized; 0 issued at December 31, 2020 and December 31, 2019 | — | — |
| Common stock, $0.00001 par value; 200,000 shares authorized; 145,174 issued and 142,305 outstanding at December 31, 2020 and 144,538 issued and 141,669 outstanding at December 31, 2019 | 1 | 1 |
| Additional paid-in capital | 550,339 | 547,050 |
| Retained deficit | (734,459) | (772,249) |
| Treasury stock, at cost; 2,869 shares at December 31, 2020 and December 31, 2019 | (24,167) | (24,167) |
| Total shareholders' deficit | (208,286) | (249,365) |
| Total liabilities and shareholders' deficit | $ 940,582 | $ 1,003,719 |

See accompanying notes.

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

| | Year Ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| Revenues: | | | |
| Oil | $ 216,419 | $ 399,790 | $ 438,798 |
| NGLs | 19,101 | 22,373 | 37,127 |
| Natural gas | 99,300 | 106,347 | 99,629 |
| Other | 11,814 | 6,386 | 5,152 |
| Total revenues | 346,634 | 534,896 | 580,706 |
| Operating costs and expenses: | | | |
| Lease operating expenses | 162,857 | 184,281 | 153,262 |
| Production taxes | 4,918 | 2,524 | 1,832 |
| Gathering and transportation | 16,029 | 25,950 | 22,382 |
| Depreciation, depletion and amortization | 97,763 | 129,038 | 131,423 |
| Asset retirement obligations accretion | 22,521 | 19,460 | 18,431 |
| General and administrative expenses | 41,745 | 55,107 | 60,147 |
| Derivative loss (gain) | (23,808) | 59,887 | (53,798) |
| Total costs and expenses | 322,025 | 476,247 | 333,679 |
| Operating income | 24,609 | 58,649 | 247,027 |
| | | | |
| Interest expense, net | 61,463 | 59,569 | 48,645 |
| Gain on debt transactions | (47,469) | - | (47,109) |
| Other expense (income), net | 2,978 | 188 | (3,871) |
| Income (loss) before income tax (benefit) expense | 7,637 | (1,108) | 249,362 |
| Income tax (benefit) expense | (30,153) | (75,194) | 535 |
| Net income | $ 37,790 | $ 74,086 | $ 248,827 |
| Basic and diluted earnings per common share | $ 0.26 | $ 0.52 | $ 1.72 |

See accompanying notes.

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

| | Common Stock Outstanding | | Additional Paid-In Capital | Retained Deficit | Treasury Stock | | Total Shareholders' Deficit |
|---|---|---|---|---|---|---|---|
| | Shares | Value | | | Shares | Value | |
| Balances at December 31, 2017 | 139,091 | $ 1 | $ 545,820 | $ (1,095,162) | 2,869 | $ (24,167) | $ (573,508) |
| Share-based compensation | — | — | 3,540 | — | — | — | 3,540 |
| Stock issued | 1,553 | — | — | — | — | — | — |
| RSUs surrendered for payroll taxes | — | — | (3,655) | — | — | — | (3,655) |
| Net income | — | — | — | 248,827 | — | — | 248,827 |
| 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) |

See accompanying notes.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| **Operating activities:** | | | |
| Net income | $ 37,790 | $ 74,086 | $ 248,827 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion, amortization and accretion | 120,284 | 148,498 | 149,854 |
| Amortization of debt items and other items | 6,834 | 5,514 | 2,850 |
| Share-based compensation | 3,959 | 3,690 | 3,540 |
| Derivative loss (gain) | (23,808) | 59,887 | (53,798) |
| Derivatives cash receipts (payments), net | 45,196 | 13,941 | (28,164) |
| Gain on debt transactions | (47,469) | — | (47,109) |
| Deferred income taxes | (30,287) | (64,102) | 500 |
| Changes in operating assets and liabilities: | | | |
| Oil and natural gas receivables | 18,537 | (9,563) | (2,361) |
| Joint interest receivables | 8,561 | (4,766) | 5,120 |
| Income taxes | 2,014 | 52,214 | 11,028 |
| Prepaid expenses and other assets | 9,563 | (9,346) | 3,383 |
| Asset retirement obligation settlements | (3,339) | (11,443) | (28,617) |
| Cash advances from JV partners | 2,028 | (15,347) | 16,629 |
| Accounts payable, accrued liabilities and other | (41,354) | (11,036) | 40,081 |
| Net cash provided by operating activities | 108,509 | 232,227 | 321,763 |
| **Investing activities:** | | | |
| Investment in oil and natural gas properties and equipment | (17,632) | (137,816) | (90,741) |
| Changes in operating assets and liabilities associated with investing activities | (26,535) | 12,110 | (15,450) |
| Acquisition of property interests | (2,919) | (188,019) | (16,782) |
| Proceeds from sales of assets, net | — | — | 56,588 |
| Purchases of furniture, fixtures and other | (530) | (89) | — |
| Net cash used in investing activities | (47,616) | (313,814) | (66,385) |
| **Financing activities:** | | | |
| Borrowings on credit facility | 25,000 | 150,000 | 61,000 |
| Repayments on credit facility | (50,000) | (66,000) | (40,000) |
| Purchase of Senior Second Lien Notes | (23,930) | — | — |
| Issuance of Senior Second Lien Notes | — | — | 625,000 |
| Extinguishment of debt – principal | — | — | (903,194) |
| Extinguishment of debt – premiums | — | — | (21,850) |
| Payment of interest on 1.5 Lien Term Loan | — | — | (6,623) |
| Payment of interest on 2nd Lien PIK Toggle Notes | — | — | (9,725) |
| Payment of interest on 3rd Lien PIK Toggle Notes | — | — | (4,672) |
| Debt transactions costs | — | (939) | (17,457) |
| Other | (670) | (2,334) | (3,622) |
| Net cash (used in) provided by financing activities | (49,600) | 80,727 | (321,143) |
| Increase (decrease) in cash and cash equivalents | 11,293 | (860) | (65,765) |
| Cash and cash equivalents, beginning of period | 32,433 | 33,293 | 99,058 |
| Cash and cash equivalents, end of period | $ 43,726 | $ 32,433 | $ 33,293 |

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 subsidiary, W & T Energy VI, LLC ("Energy VI") and through our proportionately consolidated interest in Monza Energy, LLC ("Monza"), as described in more detail in Note 4.

***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").

***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.

***Realized Prices***

The price we receive for our crude oil, natural gas liquids ("NGLs") and natural gas production directly affects our revenues, profitability, cash flows, liquidity, access to capital, proved reserves and future rate of growth. The average realized prices of these commodities decreased in 2020 compared to the average realized prices in 2019.

***Accounting Standard Updates Effective January 1, 2020***

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-13, *Financial Instruments – Credit Losses* (*Topic 326*) ("ASU 2016-13") and subsequently issued additional guidance on this topic. The new guidance eliminates the probable recognition threshold and broadens the information to consider past events, current conditions and forecasted information in estimating credit losses. This amendment did not have a material impact on our financial statements and did not affect the opening balance of Retained Deficit.

In August 2017, the FASB issued Accounting Standards Update No. 2017-12, *Derivatives and Hedging (Topic 815) – Targeted Improvements to Accounting for Hedging Activities* ("ASU 2017-12") and subsequently issued additional guidance on this topic. The amendments in ASU 2017-12 require an entity to present the earnings effect of the hedging instrument in the same income statement line in which the earning effect of the hedged item is reported. This presentation enables users of financial statements to better understand the results and costs of an entity's hedging program. Also, relative to current GAAP, this approach simplifies the financial statement reporting for qualifying hedging relationships. As we do not designate our commodity derivative instruments as qualifying hedging instruments, this amendment did not impact the presentation of the changes in fair values of our commodity derivative instruments on our financial statements.

***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.

***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, 2020 and 2019, $3.5 million and $3.6 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, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| **Customer** | | | |
| BP Products North America | 39% | 40% | 20% |
| Mercuria Energy America Inc. | 10% | ** | ** |
| Shell Trading (US) Co./ Shell Energy N.A. | ** | 11% | 30% |
| Vitol Inc. | ** | 12% | 14% |
| Williams Field Services | 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):

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Allowance for credit losses, beginning of period | $ 9,898 | $ 9,692 | $ 9,114 |
| Additional provisions for the year | 417 | 206 | 1,233 |
| Uncollectible accounts written off or collected | (1,192) | — | (655) |
| Allowance for credit losses, end of period | $ 9,123 | $ 9,898 | $ 9,692 |

***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, 2020 | December 31, 2019 |
|---|---|---|
| Derivatives – current (1) | $ 2,752 | $ 7,266 |
| Unamortized bonds/insurance premiums | 4,717 | 4,357 |
| Prepaid deposits related to royalties | 4,473 | 7,980 |
| Prepayment to vendors | 1,429 | 10,202 |
| Other | 461 | 886 |
| Prepaid expenses and other assets | $ 13,832 | $ 30,691 |

(1) Includes both open and closed contracts.

***Properties and Equipment***

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. 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.

***Oil and Natural Gas Properties and Other, Net – at cost***

Oil and natural gas properties and equipment are recorded at cost using the full cost method. There were no amounts excluded from amortization as of the dates presented in the following table (in thousands):

| | December 31, | |
|---|---|---|
| | **2020** | **2019** |
| Oil and natural gas properties and equipment | $ 8,567,509 | $ 8,532,196 |
| Furniture, fixtures and other | 20,847 | 20,317 |
| Total property and equipment | 8,588,356 | 8,552,513 |
| Less accumulated depreciation, depletion and amortization | 7,901,478 | 7,803,715 |
| Oil and natural gas properties and other, net | $ 686,878 | $ 748,798 |

***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 2020, 2019 or 2018. If average crude oil and natural gas prices decrease below average pricing during 2020, we may incur ceiling test write-downs during 2021 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 6 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 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 2020, 2019 and 2018, and as of December 31, 2020, 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 2020, 2019 and 2018, 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. These derivative instruments may or may not have qualified for hedge accounting treatment.

***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 12 for additional information.

***Other Assets (long-term)***

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

| | December 31, | |
|---|---|---|
| | 2020 | 2019 |
| ROU assets (Note 7) | $ 11,509 | $ 7,936 |
| Unamortized debt issuance costs | 2,094 | 3,798 |
| Investment in White Cap, LLC | 2,699 | 2,590 |
| Derivatives | 2,762 | 2,653 |
| Unamortized brokerage fee for Monza | 626 | 3,423 |
| Proportional consolidation of Monza's other assets (Note 4) | 1,782 | 5,308 |
| Appeal bond deposits | — | 6,925 |
| Other | 998 | 814 |
| Total other assets | $ 22,470 | $ 33,447 |

***Accrued Liabilities***

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

| | December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Accrued interest | $ 10,389 | $ 10,180 |
| Accrued salaries/payroll taxes/benefits | 4,009 | 2,377 |
| Incentive compensation plans | — | 9,794 |
| Litigation accruals | 436 | 3,673 |
| Lease liability (Note 7) | 394 | 2,716 |
| Derivatives | 13,620 | 1,785 |
| Other | 1,032 | 371 |
| Total accrued liabilities | $ 29,880 | $ 30,896 |

***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. As of the date of this filing, we have not received any response from the SBA, including any communication regarding the SBA's acceptance of our application. Management believes the Company has met all of the requirements under the PPP and will not be required to repay any portion of the grant.

We have elected to follow the income approach under IAS 20 and recognize earnings as funds are applied to covered expenses and classify the application of the funds as a reduction of the related expense in the Consolidated Statement of Operations. As a result, we have reduced expenses during the year ended December 31, 2020 and classified expense reductions consistent with our PPP fund application request. Within the Consolidated Statement of Operations, credits to *Lease operating expenses* of $2.3 million, *General and administrative expenses* of $4.2 million and reductions to *Interest expense, net* of $1.9 million were recognized for the year ended December 31, 2020. Should the SBA reject the Company's application on the utilization of funds, the Company may be required to repay all or a portion of the funds received under the PPP under an amortization schedule through April 2022 with an annual interest rate of 1%.

***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 *Other Assets* (noncurrent) and unamortized debt issuance costs associated with our other debt instruments are reported as a reduction in *Long-term debt – carrying value* in the Consolidated Balance Sheets. See Note 2 for additional information.

***Discounts Provided on Debt Issuance***

Discounts were recorded in *Long-term debt – carrying value* in the Consolidated Balance Sheets and were amortized over the term of the related debt using the effective interest method.

***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 for additional information.

***Other Liabilities (long-term)***

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

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| Dispute related to royalty deductions | $ 5,467 | $ 4,687 |
| Dispute related to royalty-in-kind | — | 250 |
| Lease liability (Note 7) | 11,360 | 4,419 |
| Derivatives | 4,384 | — |
| Black Elk escrow | 11,103 | — |
| Other | 624 | 632 |
| Total other liabilities (long-term) | $ 32,938 | $ 9,988 |

***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 10 for additional information.

***Other Expense (Income), Net***

For 2020, the amount consists primarily of expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program (as defined in Note 4). 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. For 2018, the amount consists primarily of credits related to the de-recognition of certain liabilities that had exceeded the statute of limitations, partially offset by expense 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 13 for additional information.

## 2. Long-Term Debt

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

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| Credit Agreement borrowings | $ 80,000 | $ 105,000 |
| | | |
| Senior Second Lien Notes: | | |
| Principal | 552,460 | 625,000 |
| Unamortized debt issuance costs | (7,174) | (10,467) |
| Total Senior Second Lien Notes | 545,286 | 614,533 |
| | | |
| Total long-term debt | $ 625,286 | $ 719,533 |

Aggregate annual maturities of amounts recorded for long-term debt as of December 31, 2020 are as follows (in millions): 2021–$0.0; 2022–$80.0; 2023–$552.5. See below for a discussion of our debt instruments.

***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.

On and after 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 100.000% 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 101.000% 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 Credit Agreement (defined below). 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***

Concurrently with the issuance of the Senior Second Lien Notes, we renewed our credit facility by entering into the Sixth Amended and Restated Credit Agreement (the "Credit Agreement"), dated as of October 18, 2018, among the Company, as borrower, the Guarantor Subsidiaries from time to time party thereto, Lenders from time to time party thereto and Toronto Dominion (Texas) LLC, as administrative agent with a maturity date of October 18, 2022. The primary terms of the Credit Agreement as of December 31, 2020, as amended, are as follows, with certain terms defined under the Credit Agreement:

- The borrowing base is $215.0 million.
- Letters of credit may be issued in amounts up to $30.0 million, provided availability under the Credit Agreement exists.
- From the period ended June 30, 2020 through the period ended December 31, 2021 (the "Waiver Period"), the Company will not be required to comply with the Leverage Ratio covenant. The Leverage Ratio, as defined in the Credit Agreement, is limited to 3.00 to 1.00 for quarters ending March 31, 2022 and thereafter.
- During the Waiver Period, the Company will be required to maintain a 2.00 to 1.00 ratio limit of first lien debt outstanding under the Credit Agreement on the last day of the most recent quarter to EBITDAX for the trailing four quarters.
- The Current Ratio, as defined in the Credit Agreement, must be maintained at greater than 1.00 to 1.00.
- We are required to have deposit accounts only with banks under the Credit Agreement with certain exceptions.
- We are required to provide first priority liens on properties constituting at 90% of total proved reserves of the Company as set forth on reserve reports required to be delivered under the Credit Agreement.
- To the extent there are borrowings, the Applicable Margins, as defined in the Credit Agreement, for Eurodollar Loans range from 2.75% to 3.75% per annum and the Applicable Margins for ABR loans range from 1.75% to 2.75% per annum. The specific Applicable Margin rate is based on the Borrowing Base Utilization Percentage.
- The commitment fee is 50.0 basis points.
- We are required to have derivative contracts for a minimum of 50% of projected production for 18 months based on existing proved developed producing reserves and certain other criteria and have met this requirement. We may enter into derivative contracts with counter parties within the Credit Agreement or with other counter parties meeting certain criteria described in the Credit Agreement.

Availability under the Credit Agreement is subject to semi-annual redeterminations of our borrowing base to occur on or before May 15 and November 14 each calendar year, and certain additional redeterminations that may be requested at the discretion of either the lenders or the Company. The borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under the Credit Agreement. The Credit Agreement's security is collateralized by a first priority lien on substantially all of our oil and natural gas properties and certain personal property.

Borrowings outstanding under the Credit Agreement are reported in the table above. As of December 31, 2020 and 2019, we had $4.4 million and $5.8 million, respectively, outstanding in letters of credit under the Credit Agreement. The estimated annual effective interest rate on borrowings, exclusive of debt issuance costs, commitment fees and other fees was 3.8%.

As of December 31, 2020 and for all prior measurement periods, we were in compliance with all applicable covenants of the Credit Agreement and Senior Second Lien Notes.

On January 6, 2021, we entered into a Waiver, Consent to Second Amendment to Intercreditor Agreement and Fifth Amendment to Sixth Amended and Restated Credit Agreement (the "Fifth Amendment") dated as of January 6, 2021, among the Company, certain of its guarantor subsidiaries, Toronto Dominion (Texas) LLC, individually and as administrative agent, and certain of the Company's lenders and other parties thereto (as heretofore amended, the "Credit Agreement"). The Fifth Amendment, which became effective as of January 6, 2021, amends the Sixth Amended and Restated Credit Agreement (the "Fifth Amendment") dated as of October 18, 2018. The Fifth Amendment includes the following changes, among other things, to the Credit Agreement:

- Reduces the borrowing base under the Credit Agreement from $215.0 million to $190.0 million.
- Amends and waives certain hedging requirements for projected natural gas production volumes of the Company to the extent that certain identified existing hedge contracts may cause non-compliance with minimum swap requirements for hedged volumes for any test date related to any calendar quarterly period ended on or before December 31, 2022 and requires that all natural gas hedge contracts entered into after December 13, 2020 until the December 31, 2022 test date (or such earlier date as provided in the Fifth Amendment) shall be in the form of swaps and not collars or puts until swaps represent at least 50% of natural gas hedge positions for all months required to be hedged by the Credit Agreement.
- Establishes procedures for the Company to propose additional hedge counterparties and directs the administrative agent to enter into hedge intercreditor agreements with one or more hedge counterparties from time to time.
- Establishes a customary anti-cash hoarding prepayment requirement in the event the cash balances of the Company exceed $25.0 million (subject to customary adjustments) at the end of any calendar month.

Under the Fifth Amendment, the lenders under the Credit Agreement have also consented to and executed certain conforming amendments necessitated by the Fifth Amendment proposed to be made to that certain Intercreditor Agreement among Toronto Dominion (Texas) LLC, as Original Priority Lien Agent and Wilmington Trust, National Association, as Second Lien Trustee and as Second Lien Collateral Agent.

For information about fair value measurements of our long-term debt, refer to Note 3.

***Refinancing Transaction in 2018***

On October 18, 2018, funds from the issuances of the Senior Second Lien Notes, borrowings under the Credit Agreement and cash on hand were used to repurchase and retire, repay or redeem all of the prior debt instruments, which are listed below. The issuance of the Senior Second Lien Notes, execution of the Credit Agreement and extinguishment of the prior debt instruments are collectively referred to as the "Refinancing Transaction". A net gain of $47.1 million was recorded as a result of the Refinancing Transaction, comprised of the write off of carrying value adjustments of the prior debt instruments and partially offset by premiums paid. The effect on both basic and diluted earnings per share for 2018 was $0.33 per share, which assumes the gain would not affect our income tax expense for 2018.

***Prior Debt Instruments***

The following debt instruments were repurchased and retired, repaid or redeemed, including interest and applicable premiums as part of the Refinancing Transaction on October 18, 2018:

- 11.00% 1.5 Lien Term Loan, (the "1.5 Lien Term Loan") due November 15, 2019, $75.0 million principal outstanding on October 18, 2018.
- 9.00% Term Loan, due May 15, 2020, $300.0 million principal outstanding on October 18, 2018 (the "Second Lien Term Loan").
- 9.00%/10.75% Senior Second Lien PIK Toggle Notes (the "Second Lien PIK Toggle Notes"), due May 15, 2020, $177.5 million principal outstanding on October 18, 2018.
- 8.50%/10.00% Senior Third Lien PIK Toggle Notes (the "Third Lien PIK Toggle Notes"), due June 15, 2021, $160.9 million principal outstanding on October 18, 2018.
- 8.500% Senior Notes (the "Unsecured Senior Notes"), due June 15, 2019, $189.8 million principal outstanding on October 18, 2018.

**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.

The following tables present the fair value of our derivatives and long-term debt (in thousands):

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| **Assets:** | | |
| Derivatives instruments - open contracts, current | $ 2,705 | $ 6,921 |
| Derivatives instruments - open contracts, long-term | 2,762 | 2,653 |
| **Liabilities:** | | |
| Derivatives instruments - open contracts, current | 13,291 | 1,785 |
| Derivatives instruments - open contracts, long-term | 4,384 | — |

| | December 31, 2020 | | December 31, 2019 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| **Liabilities:** | | | | |
| Credit Agreement | $ 80,000 | $ 80,000 | $ 105,000 | $ 105,000 |
| Senior Second Lien Notes | 545,286 | 393,352 | 614,533 | 597,188 |

As of December 31, 2020 and 2019, the carrying value of our open derivative contracts equaled the estimated fair value. We measure the fair value of our derivative contracts by applying the income approach using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used to measure the fair value of our derivative contracts are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads and published commodity future prices.

The fair value of our Senior Second Lien Notes is based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our Credit Agreement approximates fair value because the interest rates are variable and reflective of current market rates.

## 4. 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, 2020.

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.

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.

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, 2020, nine wells have been completed of which six were producing as of December 31, 2020. W&T is the operator for seven of the nine wells completed through December 31, 2020.

Through December 31, 2020, members of Monza made partner capital contributions, including our contributions of working interest in the drilling projects, to Monza totaling $289.3 million and received cash distributions totaling $70.8 million. Our net contribution to Monza, reduced by distributions received, as of December 31, 2020 was $51.8 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, 2020, 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, 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. As of December 31, 2019, in the Consolidated Balance Sheet, we recorded $16.1 million, net, in *Oil and natural gas properties and other, net*, $5.3 million in *Other assets,* $0.1 million in ARO and $2.7 million, net, increase in working capital in connection with our proportional interest in Monza’s assets and liabilities. Additionally, during 2020 and 2019, 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, 2020 and 2019 were $7.3 million and $5.3 million, respectively, which are included in the Consolidated Balance Sheet in *Advances from joint interest partners*. For 2020, in the Consolidated Statement of Operations, we recorded $8.4 million in *Total revenues* and $12.1 million in *Operating costs and expenses* in connection with our proportional interest in Monza’s operations. For 2019, in the Consolidated Statement of Operations, we recorded $11.9 million in *Total revenues* and $7.4 million in *Operating costs and expenses* in connection with our proportional interest in Monza’s operations.

## 5. 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.

***Heidelberg Field***

On April 5, 2018, we completed the purchase of Cobalt International Energy, Inc.'s 9.375% non-operated working interests located in Green Canyon blocks 859, 903 and 904 (the "Heidelberg Field"). After taking into account customary closing adjustments and an effective date of January 1, 2018, cash consideration was $16.8 million which includes cash expenses related to the acquisition. We determined that the assets acquired did not meet the definition of a business; therefore, the transaction was accounted for as an asset acquisition. In connection with this transaction, we were required to furnish a letter of credit of $9.4 million to a pipeline company as consignee. We recognized ARO of $3.6 million as a component of the transaction. In conjunction with the purchase of an interest in the Heidelberg field, we assumed contracts with certain pipeline companies that contain minimum quantities obligations through 2028 resulting in an estimated commitment of $19.6 million as of the purchase date.

***Permian Basin***

On September 28, 2018, we completed the divestiture of substantially all of our ownership in an overriding royalty interests in the Permian Basin. The net proceeds received were $56.6 million, which was recorded as a reduction to our full-cost pool.

## 6. 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, | |
|---|---|---|
| | **2020** | **2019** |
| Asset retirement obligations, beginning of period | $ 355,594 | $ 310,137 |
| Liabilities settled | (3,339) | (11,443) |
| Accretion of discount | 22,521 | 19,460 |
| Liabilities incurred and assumed through acquisition | 4,860 | 29,887 |
| Revisions of estimated liabilities (1) | 13,068 | 7,553 |
| Asset retirement obligations, end of period | 392,704 | 355,594 |
| Less current portion | 17,188 | 21,991 |
| Long-term | $ 375,516 | $ 333,603 |

(1) Revisions in 2020 and 2019 were due to changes in scope, weather impact, revisions to actual expenses versus estimates and revisions related to non-operated properties.

## 7. 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, | |
|---|---|---|
| | 2020 | 2019 |
| Operating lease cost, excluding short-term leases | $ 3,060 | $ 2,902 |
| Short-term lease cost (1) | 1,633 | 22,152 |
| Total lease cost | $ 4,693 | $ 25,054 |

(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, 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, | |
|---|---|---|
| | 2020 | 2019 |
| ROU assets | $ 11,509 | $ 7,936 |
| Lease liability: | | |
| Accrued liabilities | $ 394 | $ 2,716 |
| Other liabilities | 11,360 | 4,419 |
| Total lease liability | $ 11,754 | $ 7,135 |

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

| | December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Weighted average remaining lease term: | 14.8 years | 14.3 years |
| Weighted average discount rate: | 10.2% | 10.4% |

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

| | December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Operating cash outflow from operating leases | $ 1,825 | $ 1,827 |
| Right-of-use assets obtained in exchange for new operating lease liabilities | $ 5,142 | $ 6,373 |

Undiscounted future minimum payments as of December 31, 2020 are as follows (in thousands):

| | |
|---|---|
| 2021 | $ 394 |
| 2022 | 1,134 |
| 2023 | 1,625 |
| 2024 | 2,023 |
| 2025 | 1,512 |
| Thereafter | 17,461 |
| Total lease payments | 24,149 |
| Present value adjustment | (12,395) |
| Total | $ 11,754 |

**8. Restricted Deposits for ARO**

Restricted deposits as of December 31, 2020 and 2019 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 15 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 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. $11.1 million was recorded in *Other Liabilities* as of December 31, 2020 as our estimate of the additional asset retirement obligations to be funded from the restricted deposit account.

**9. Derivative Financial Instruments**

During 2020, 2019 and 2018, 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, 2020 are presented in the following tables:

**Crude Oil: Open Swap Contracts, Priced off WTI (NYMEX)**

| Period | Notional Quantity (Bbls/day) | Notional Quantity (Bbls) | Weighted Strike Price |
|---|---|---|---|
| Jan 2021 - Dec 2021 | 4,000 | 1,460,000 | $ 42.06 |
| Jan 2022 - Feb 2022 | 3,000 | 177,000 | $ 42.98 |
| Mar 2022 - May 2022 | 2,044 | 188,006 | $ 42.33 |

**Crude Oil: Open Collar Contracts - Priced off WTI (NYMEX)**

| Period | Notional Quantity (Bbls/day) | Notional Quantity (Bbls) | Put Option Weighted Strike Price (Bought) | Call Option Weighted Strike Price (Sold) |
|---|---|---|---|---|
| Jan.2021 - Feb 2022 | 1,770 | 750,422 | $ 35.00 | $ 50.00 |
| Mar 2022 - May 2022 | 2,000 | 184,000 | $ 35.00 | $ 48.50 |

**Natural Gas: Open Call Contracts, Bought, Priced off Henry Hub (NYMEX)**

| Period | Notional Quantity (MMBtu/day) | Notional Quantity (MMBtu) | Strike Price |
|---|---|---|---|
| Feb 2021 - Dec. 2022 | 40,000 | 27,960,000 | $ 3.00 |

**Natural Gas: Open Swap Contracts, Bought, Priced off Henry Hub (NYMEX)**

| Period | Notional Quantity (MMBtu/day) | Notional Quantity (MMBtu) | Strike Price |
|---|---|---|---|
| Jan 2021 - Dec 2021 | 10,000 | 3,650,000 | $ 2.62 |
| Jan 2022 | 20,000 | 620,000 | $ 2.79 |
| Feb 2022 | 30,000 | 840,000 | $ 2.79 |
| Mar 2022 - May 2022 | 10,544 | 970,075 | $ 2.69 |

**Natural Gas: Open Collar Contracts, Priced off Henry Hub (NYMEX)**

| Period | Notional Quantity (MMBtu/day) | Notional Quantity (MMBtu) | Put Option Weighted Strike Price (Bought) | Call Option Weighted Strike Price (Sold) |
|---|---|---|---|---|
| Jan 2021 - Dec 2022 | 40,000 | 29,200,000 | $ 1.83 | $ 3.00 |
| Jan 2021 - Dec 2021 | 30,000 | 10,950,000 | $ 2.18 | $ 3.00 |
| Jan 2022 - Feb 2022 | 30,000 | 1,770,000 | $ 2.20 | $ 4.50 |
| Mar 2022 - May 2022 | 10,000 | 92,000 | $ 2.25 | $ 3.40 |

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

| | December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Prepaid and other assets – current | $ 2,752 | $ 7,266 |
| Other assets – non-current | 2,762 | 2,653 |
| Accrued liabilities | 13,620 | 1,785 |

The amounts recorded on the Consolidated Balance Sheets are on a gross basis. If these were recorded on a net settlement basis, it would not have resulted in any differences in reported amounts.

Changes in the fair value and settlements of our commodity derivative contracts were as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Derivative loss (gain) | $ (23,808) | $ 59,887 | $ (53,798) |

Cash receipts (payments), net, on commodity derivative contract settlements, which include derivative premium payments, 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Derivative cash receipts (payments), net | $ 45,196 | $ 13,941 | $ (28,164) |

## 10. 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.

### *Share-based Awards: Restricted Stock Units*

During 2019 and 2018, 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 and are granted to certain employees, and are subject to satisfaction of certain predetermined performance criteria and adjustments at the end of the applicable performance period based on the results achieved.

As of December 31, 2020, there were 10,347,591shares 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 2020, 2019 and 2018, 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 2019 grants, which were subject to predetermined performance criteria applied against the applicable performance period. These RSUs continue to be subject to employment-based criteria and vesting generally occurs in December of the second year after the grant. See the table below for anticipated vesting by year.

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 2019 and 2018 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.

During 2019, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) net 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; litigation; and other ("Adjusted EBITDA") for 2019 and (ii) Adjusted EBITDA as a percent of total revenue ("Adjusted EBITDA Margin") for 2019. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2019, the Company achieved below target and above threshold for both Adjusted EBITDA and Adjusted EBITDA Margin, therefore only a portion of the amount granted will be eligible for vesting.

During 2018, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2018 and (ii) Adjusted EBITDA Margin for 2018. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2018, the Company achieved target for both Adjusted EBITDA and Adjusted EBITDA Margin.

A summary of activity related to RSUs is as follows:

| | 2020 | | 2019 | | 2018 | |
|---|---|---|---|---|---|---|
| | **Restricted Stock Units** | **Weighted Average Grant Date Fair Value Per Share** | **Restricted Stock Units** | **Weighted Average Grant Date Fair Value Per Share** | **Restricted Stock Units** | **Weighted Average Grant Date Fair Value Per Share** |
| Nonvested, beginning of period | 1,614,722 | $ 5.73 | 3,355,917 | $ 3.90 | 5,765,251 | $ 2.48 |
| Granted | - | - | 994,698 | 4.51 | 988,955 | 6.90 |
| Vested | (787,203) | 6.90 | (1,475,373) | 2.76 | (2,261,665) | 2.21 |
| Forfeited | (63,831) | 5.80 | (1,260,520) | 3.37 | (1,136,624) | 2.68 |
| Nonvested, end of period | 763,688 | $ 4.51 | 1,614,722 | $ 5.73 | 3,355,917 | $ 3.90 |

Subject to the satisfaction of service conditions, the RSUs outstanding as of December 31, 2020 are eligible to vest in 2021.

RSUs fair value at grant date - There were no RSUs granted during 2020. During 2019 and 2018, the grant date fair value of RSUs granted was $4.5 million and $6.8 million, respectively.

RSUs fair value at vested date - The fair value of the RSUs that vested during 2020, 2019 and 2018 was $2.0 million, $7.0 million and $11.0 million, respectively, based on the Company's closing price on the vesting date.

***Share-Based Awards: Restricted Stock***

Under the Directors Compensation Plan, shares of restricted stock ("Restricted Shares") were issued in 2020, 2019 and 2018 to the Company's non-employee directors as a component of their compensation arrangement. Vesting occurs upon completion of the specified vesting period and one-third of each grant vests each year over a three-year period. The holders of Restricted Shares generally have the same rights as a shareholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. Restricted Shares are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restriction period.

As of December 31, 2020, there were 473,244 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:

| | 2020 | | 2019 | | 2018 | |
|---|---|---|---|---|---|---|
| | **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 | 123,180 | $ 4.55 | 181,832 | $ 3.08 | 246,528 | $ 2.27 |
| Granted | 109,376 | 2.56 | 46,360 | 6.04 | 41,544 | 6.74 |
| Vested | (78,428) | 2.38 | (105,012) | 2.67 | (106,240) | 2.64 |
| Nonvested, end of period | 154,128 | $ 4.24 | 123,180 | $ 4.55 | 181,832 | $ 3.08 |

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2020 are expected to vest as follows:

| | **Restricted Shares** |
|---|---|
| 2021 | 138,676 |
| 2022 | 15,452 |
| Total | 154,128 |

Restricted stock fair value at grant date - The grant date fair value of restricted stock granted during 2020, 2019 and 2018 was $0.3 million each year for all years presented 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 2020, 2019 and 2018 was $0.2 million, $0.5 million and $0.7 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Share-based compensation expense from: | | | |
| Restricted stock units | $ 3,555 | $ 3,410 | $ 3,260 |
| Restricted stock | 404 | 280 | 280 |
| Total | $ 3,959 | $ 3,690 | $ 3,540 |

As of December 31, 2020, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $1.2 million and $0.2 million, respectively. Unrecognized compensation expense will be recognized through November 2021 for our RSUs and April 2022 for our Restricted Shares.

***Cash-based Awards***

In addition to share-based compensation, short-term, cash-based awards were granted under the Plan to substantially all eligible employees in 2019 and 2018. The short-term, cash-based awards, which are generally a short-term component of the Plan, are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. In addition, these cash-based awards included an additional financial condition requiring Adjusted EBITDA less reported Interest Expense Incurred for any fiscal quarter plus the three preceding quarters to exceed defined levels measured over defined time periods for each cash-based award. No cash-based incentive awards were granted in 2020 under the Plan, and therefore, no cash-based incentive award compensation expense for 2020 has been recorded. The Compensation Committee has deferred its decision regarding the potential awarding of incentive compensation, including by the exercise of discretion. During 2018, long-term, cash awards were granted to certain employees subject to pre-define performance criteria. Expense is recognized over the service period once the business criteria, individual performance criteria and financial condition are met.

- For the 2019 cash-based awards, a portion of the business criteria and individual performance criteria were achieved. The financial condition requirement of Adjusted EBITDA less reported Interest Expense Incurred exceeding $200 million over four consecutive quarters was achieved; therefore, incentive compensation expense was recognized in 2019 for a portion of the 2019 cash-based awards. Payments were made in March 2020 and are subject to all the terms of the 2019 Annual Incentive Award Agreement.

- In 2018, the Company, as part of its long-term incentive program, granted cash awards to certain employees that will vest over a three-year service period.

- For the 2018 long-term, cash-based awards, incentive compensation expense was determined based on the Company achieving certain performance metrics for 2018 and is being recognized over the September 2018 to November 2020 period (the service period of the award). The 2018 long-term, cash-based awards were paid on December 15, 2020 subject to participants meeting certain employment-based criteria.

- For the 2018 short-term, cash-based awards, incentive compensation expense was determined based on the Company achieving certain performance metrics for 2018 combined with individual performance criteria for 2018 and was recognized over the January 2018 to February 2019 period. The 2018 short-term, cash-based awards were paid during March 2019.

***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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Share-based compensation included in: | | | |
| General and administrative | $ 3,959 | $ 3,690 | $ 3,540 |
| Cash-based incentive compensation included in: | | | |
| Lease operating expense | 849 | 2,206 | 3,596 |
| General and administrative | 4,019 | 8,897 | 9,586 |
| Total charged to operating income | $ 8,827 | $ 14,793 | $ 16,722 |

***Discretionary Bonus to Employees in 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 $7.6 million, payable in equal installments on March 15, 2021 and April 15, 2021, subject to employment on those dates.

**11. 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 2020, 2019, and 2018 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 $2.3 million, $2.0 million, and $2.0 million for 2020, 2019 and 2018, respectively.

## 12. Income Taxes

***Income Tax (Benefit) Expense***

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Current | $ 134 | $ (11,092) | $ 35 |
| Deferred | (30,287) | (64,102) | 500 |
| Total income tax (benefit) expense | $ (30,153) | $ (75,194) | $ 535 |

***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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Income tax (benefit) expense at the federal statutory rate | $ 1,604 | $ (233) | $ 52,366 |
| Compensation adjustments | 1,373 | 971 | 457 |
| State income taxes | 75 | (175) | 560 |
| Uncertain tax position | — | (11,523) | — |
| Impact of U.S. legislative changes | (21,345) | — | 487 |
| Valuation allowance | (12,018) | (64,704) | (53,980) |
| Other | 158 | 470 | 645 |
| Total income tax (benefit) expense | $ (30,153) | $ (75,194) | $ 535 |

Our effective tax rate for the years 2020, 2019 and 2018 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, effective tax rates for the years 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, 2020 | December 31, 2019 |
|---|---|---|
| Deferred tax liabilities: | | |
| Property and equipment | $ 37,535 | $ 21,647 |
| Derivatives | — | — |
| Investment in non-consolidated entity | 8,070 | 14,716 |
| Other | 2,588 | 2,283 |
| Total deferred tax liabilities | 48,193 | 38,646 |
| Deferred tax assets: | | |
| Property and equipment | — | — |
| Derivatives | 3,416 | 1,409 |
| Asset retirement obligations | 84,332 | 76,924 |
| Federal net operating losses | 47,307 | 15,265 |
| State net operating losses | 8,136 | 7,393 |
| Interest expense limitation carryover | 16,304 | 48,458 |
| Share-based compensation | 419 | 965 |
| Valuation allowance | (22,361) | (54,436) |
| Other | 4,843 | 6,584 |
| Total deferred tax assets | 142,396 | 102,562 |
| Net deferred tax assets (liabilities) | $ 94,203 | $ 63,916 |

***Income Taxes Receivable, Refunds and Payments***

As of December 31, 2020, we do not have any current income taxes receivable. As of December 31, 2019, we had current income taxes receivable of $1.9 million which was received in 2020 and related to a net operating loss ("NOL") carryback claim for the year 2017 that we carried back to prior years. During 2019, we received refunds of $51.8 million related to our NOL carryback claims for the years 2012, 2013 and 2014 that were carried back to prior years. Additionally, we received $4.5 million in interest income associated with the refunds in 2019. These carryback claims, in addition to the 2017 claim, were 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, 2020 and 2019, 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, 2020 (in thousands):

| | Amount | Expiration Year |
|---|---|---|
| Federal net operating loss | $ 225,274 | earliest is 2037 |
| State net operating loss | 136,440 | 2026-2038 |
| Interest expense limitation carryover | 75,341 | N/A |

***Valuation Allowance***

During 2020 and 2019, we recorded a decrease in the valuation allowance of $32.1 million and $63.3 million, respectively, related to federal and state deferred tax assets. 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.

Throughout 2020, the Company has been assessing the realizability of our deferred tax assets by considering positive factors such as, when considering the Company's results for the twelve months ended December 31, 2018, 2019 and 2020, the Company has cumulative pre-tax income during this three year period. Based on the assessment, we determined that the Company's ability to maintain long-term profitability despite near-term changes in commodity prices and operating costs demonstrated that a portion of the Company's net deferred tax assets would more likely than notbe realized. During 2020, we released $32.1 million of the valuation allowance, resulting in an income tax benefit in 2020 primarily as a result of 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 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, 2020, the Company's valuation allowance was $22.4 million.

***Uncertain Tax Positions***

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. During 2019, the settlement of our net operating loss carryback claims with the IRS effectively allowed us to also settle our uncertain tax position which resulted in a change in our unrecognized tax benefits and materially impacted our income tax benefit.

Reconciliation of the balances of our uncertain tax positions are as follows (in thousands):

| | December 31, | |
|---|---|---|
| | **2020** | **2019** |
| Balance, beginning of period | $ — | $ 9,482 |
| Decrease during the period | — | (9,482) |
| Balance, end of period | $ — | $ — |

***Years open to examination***

The tax years from 2017 through 2020 remain open to examination by the tax jurisdictions to which we are subject.

## 13. 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Net income | $ 37,790 | $ 74,086 | $ 248,827 |
| Less portion allocated to nonvested shares | 437 | 1,371 | 9,727 |
| Net income allocated to common shares | $ 37,353 | $ 72,715 | $ 239,100 |
| Weighted average common shares outstanding | 141,622 | 140,583 | 139,002 |
| Basic and diluted earnings per common share | $ 0.26 | $ 0.52 | $ 1.72 |

## 14. Supplemental Cash Flow Information

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Supplemental cash items: | | | |
| Cash paid for interest (1) | $ 59,183 | $ 66,720 | $ 61,501 |
| Cash paid for income taxes | 159 | 51 | 138 |
| Cash refunds received for income taxes | 2,007 | 51,833 | 11,126 |
| Cash paid for share-based compensation (2) | — | — | 1,130 |
| Cash received for interest income | 603 | 7,720 | 2,385 |
| | | | |
| Non-cash investing activities: | | | |
| Accruals of property and equipment | 3,035 | 29,662 | 18,575 |
| ARO - additions, dispositions and revisions, net | 17,928 | 37,440 | 19,877 |

(1) During 2018, cash paid for interest included amounts related to the debt instruments issued during 2016, which were accounted for under ASC 470-60 and recorded against the carrying value of the debt instruments on the Consolidated Balance Sheets and included in *financing activities* on the Consolidated Statements of Cash Flows. No interest was capitalized in the periods presented.

(2) During 2020 and 2019, only common shares were used to settle vested RSUs and Restricted Shares. During 2018, cash was used to settle vested RSUs related to the retirement of executive officers and shares of common stock were used to settle all other vested RSUs and to settle Restricted Shares.

**15. Commitments**

See Note 7 for information on leases.

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, 2020, we had surety bonds related to the agreement with Total E&P totaling $93.7 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, 2020, 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 $30.0 million of surety bonds as of December 31, 2020. This amount increases on June 1 of the following years to $33.0 million - 2021; $36.3 million - 2022; $40.0 million - 2023; $44.0 million - 2024; $48.3 million - 2025, and future increases in increments ranging $4.0 million to $9.0 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 2020, 2019 and 2018, 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 Total E&P and Shell agreements described above, were $5.4 million, $4.7 million, and $5.9 million during 2020, 2019 and 2018, 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: 2021–$5.8 million; 2022–$5.6 million; 2023 - $5.7 million; 2024 - $5.6 million; 2025–$5.6 million and thereafter–$57.9 million. 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 2028. For 2020, 2019 and 2018 expense recognized for the difference between the quantities shipped and the minimum obligations was $4.5 million, $4.5 million and $2.3 million, respectively. As of December 31, 2020, the estimated future costs are: 2021–$2.5 million; 2022–$1.8 million; 2023–$1.2 million; 2024 - $0.8 million; 2025 - $0.6 million and thereafter–$0.7 million.

We have no drilling rig commitments as of December 31, 2020.

## 16. Related Parties

During 2020, 2019 and 2018, there were certain transactions between us and other companies our 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 $0.3 million, $1.2 million and $1.3 million for the years 2020, 2019 and 2018 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 $14.4 million, $22.8 million and $21.0 million in 2020, 2019 and 2018, respectively. The spouse received commissions partially based on services rendered to W&T which were approximately $0.1 million in 2020, 2019 and 2018. 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. See Note 4 for information on a related party transaction concerning Monza.

## 17. Contingencies

### *Apache Lawsuit*

On December 15, 2014, Apache filed a lawsuit against the Company, Apache Deepwater, L.L.C. vs. W&T Offshore, Inc., alleging that W&T breached the joint operating agreement related to, among other things, the abandonment of three deepwater wells in the Mississippi Canyon area of the Gulf of Mexico. A trial court judgment was rendered from the U.S. District Court for the Southern District of Texas on May 31, 2017 directing the Company to pay Apache $49.5 million including prejudgment interest, attorney's fees and costs. We unsuccessfully appealed that judgment through a process ending with the denial of a writ of certiorari to the United States Supreme Court. A deposit of $49.5 million we made in June of 2017 with the registry of the court was distributed during 2019 pursuant to an agreement with Apache.

Due to funds being distributed during 2019, amounts previously recorded of $49.5 million in Other assets (long-term) and $49.5 million recorded in Other liabilities (long-term) on the Consolidated Balance Sheet as of December 31, 2018 were reversed during 2019 and interest income of $1.9 million was recorded in Interest expense, net on the Consolidated Statements of Operations in 2019.

***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 penal 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, 2020 to such amount.

***Notices of Proposed Civil Penalty Assessment***

During 2020 and 2019, we did not pay any civil penalties to the BSEE related to Incidents of Noncompliance ("INCs") at various offshore locations. In January 2021, we executed a Settlement Agreement with the Bureau of Safety and Environmental Enforcement ("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, with the first installment due in March 2021. In addition, W&T committed to implement a Safety Improvement Plan with various deliverables due over a period ending in 2022.

***Royalties – "Unbundling" Initiative***

The ONRR has publicly announced an "unbundling" initiative to revise the methodology employed by producers in determining the appropriate allowances for transportation and processing costs that are permitted to be deducted in determining royalties under Federal oil and gas leases. The ONRR's initiative requires re-computing allowable transportation and processing costs using revised guidance from the ONRR going back 84 months for every gas processing plant that processed our gas. In the second quarter of 2015, pursuant to the initiative, we received requests from the ONRR for additional data regarding our transportation and processing allowances on natural gas production related to a specific processing plant. We also received a preliminary determination notice from the ONRR asserting that our allocation of certain processing costs and plant fuel use at another processing plant was not allowed as deductions in the determination of royalties owed under Federal oil and gas leases. We have submitted revised calculations covering certain plants and time periods to the ONRR. As of the filing date of this Form 10-K, we have not received a response from the ONRR related to our submissions. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under our Federal oil and gas leases for current and prior periods. During 2020, 2019 and 2018, we paid $0.2 million, $0.4 million and $0.6 million, respectively, of additional royalties and expect to pay more in the future. We are not able to determine the range of any additional royalties or if such amounts would be material.

***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 2020 or 2019.

***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.

## 18. Selected Quarterly Financial Data—UNAUDITED

Unaudited quarterly financial data are as follows (in thousands, except per share amounts):

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| Year Ended December 31, 2020 | | | | |
| Revenues | $ 124,128 | $ 55,241 | $ 72,517 | 94,748 |
| Operating (loss) income | 71,811 | (28,041) | (19,510) | 349 |
| Net (loss) income (1) | 65,980 | (5,904) | (13,339) | (8,947) |
| Basic and diluted (loss) earnings per common share (2) | 0.46 | (0.04) | (0.09) | (0.06) |
| Year Ended December 31, 2019 | | | | |
| Revenues | $ 116,080 | $ 134,701 | $ 132,221 | $ 151,894 |
| Operating income | (30,976) | 37,379 | 35,399 | 16,847 |
| Net (loss) income (1) | (47,761) | 36,389 | 75,899 | 9,559 |
| Basic and diluted earnings per common share (2) | (0.34) | 0.25 | 0.53 | 0.07 |

(1) During 2020, we recorded a derivative (gain) loss of $(61.9) million, 15.4 million, 11.2 million, and $11.5 million in the first, second, third and fourth quarters, respectively. During 2020, we recorded gain on debt transactions of $47.5 million. During 2020, we recorded income tax expense (benefit) of $6.5 million, ($8.7) million, ($21.1) million and ($6.9) million in the first, second, third and fourth quarters, respectively. During 2019, we recorded a derivative loss (gain) of $48.9 million, ($1.8) million, ($5.9) million, and $18.7 million in the first, second, third and fourth quarters, respectively. During 2019, we recorded income tax expense (benefit) of $0.2 million, ($11.7) million, ($55.5) million and ($8.2) million in the first, second, third and fourth quarters, respectively.

(2) The sum of the individual quarterly earnings (loss) per common share may not agree with the yearly amount due to each quarterly calculation is based on income for that quarter and the weighted average common shares outstanding for that quarter.

## 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):

| | December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Net capitalized costs:** | | | |
| Proved oil and natural gas properties and equipment | $ 8,567.5 | $ 8,532.2 | $ 8,169.9 |
| Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities | (7,890.9) | (7,793.3) | (7,665.1) |
| Net capitalized costs related to producing activities | $ 676.6 | $ 738.9 | $ 504.8 |

### *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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Costs incurred: (1)** | | | |
| Proved properties acquisitions | $ 8.1 | $ 223.8 | $ 24.1 |
| Exploration (2) (3) | 7.4 | 30.6 | 49.9 |
| Development | 23.6 | 114.5 | 56.2 |
| Total costs incurred in oil and gas property acquisition, exploration and development activities | $ 39.1 | $ 368.9 | $ 130.2 |

(1) Includes net additions from capitalized ARO of $15.2 million, $37.5 million, and $20.3 million during 2020, 2019, and 2018, respectively. These adjustments for ARO are associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.
(2) Includes seismic costs of $0.3 million, $7.8 million, and $1.5 million incurred during 2020, 2019, and 2018, respectively.
(3) Includes geological and geophysical costs charged to expense of $4.5 million, $5.7 million, and $5.4 million during 2020, 2019, and 2018, 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Depreciation, depletion, amortization and accretion per Boe | $ 7.82 | $ 10.01 | $ 11.24 |

***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 22.1% of our proved developed non-producing reserves as of December 31, 2020 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, 2020. In prior years, we were not the operator of substantially all proved undeveloped reserves.

The following sets forth estimated quantities of our net proved, proved developed and proved undeveloped oil, NGLs and natural gas 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”*.

| | Oil (MMBbls) | NGLs (MMBbls) | Natural Gas (Bcf) | Total Energy Equivalent Reserves (1) | |
|---|---|---|---|---|---|
| | | | | Oil Equivalent (MMBoe) | Natural Gas Equivalent (Bcfe) |
| Proved reserves as of Dec. 31, 2017 | 34.4 | 7.8 | 192.2 | 74.2 | 445.3 |
| Revisions of previous estimates (2) | 11.6 | 2.8 | 40.4 | 21.1 | 126.7 |
| Extensions and discoveries (3) | 0.5 | 0.3 | 7.7 | 2.1 | 12.6 |
| Purchase of minerals in place (4) | 1.5 | 0.4 | 9.4 | 3.4 | 20.7 |
| Sales of minerals in place (5) | (2.2) | (0.2) | (7.2) | (3.5) | (21.2) |
| Production | (6.7) | (1.3) | (32.0) | (13.3) | (80.0) |
| Proved reserves as of Dec. 31, 2018 | 39.1 | 9.8 | 210.5 | 84.0 | 504.1 |
| Revisions of previous estimates (6) | 1.4 | (1.5) | (16.9) | (3.0) | (18.2) |
| Extensions and discoveries (7) | 0.9 | 0.1 | 1.2 | 1.1 | 6.7 |
| Purchase of minerals in place (8) | 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 Dec. 31, 2019 | 37.8 | 24.5 | 571.1 | 157.4 | 944.5 |
| Revisions of previous estimates (9) | (0.9) | (5.9) | 31.6 | (1.4) | (8.8) |
| Extensions and discoveries (10) | 0.2 | 0.0 | 0.2 | 0.2 | 1.3 |
| Purchase of minerals in place (11) | 0.7 | 0.4 | 14.8 | 3.6 | 21.8 |
| Production | (5.6) | (1.7) | (48.4) | (15.4) | (92.3) |
| Proved reserves as of Dec. 31, 2020 | 32.2 | 17.3 | 569.3 | 144.4 | 866.5 |
| | | | | | |
| Year-end proved developed reserves: | | | | | |
| 2020 | 24.0 | 16.5 | 550.2 | 132.2 | 793.3 |
| 2019 | 28.0 | 21.7 | 504.9 | 133.8 | 802.9 |
| 2018 | 31.5 | 7.8 | 166.8 | 67.0 | 402.2 |
| | | | | | |
| Year-end proved undeveloped reserves: | | | | | |
| 2020 (12) | 8.2 | 0.9 | 19.1 | 12.2 | 73.2 |
| 2019 | 9.8 | 2.8 | 66.2 | 23.6 | 141.6 |
| 2018 | 7.6 | 2.0 | 43.7 | 17.0 | 101.9 |

Volume measurements:
MMBbls – million barrels for crude oil, condensate or NGLs
MMBoe – million barrels of oil equivalent
Bcf – billion cubic feet
Bcfe – billion cubic feet of gas equivalent

(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) Primarily related to upward revisions at our Mahogany field and our Ship Shoal 028 field. Additionally, increases of 2.3 MMBoe were due to price revisions.

(3) Primarily related to extensions and discoveries of 1.3 MMBoe at our Viosca Knoll 823 (Virgo) field and 0.7 MMBoe at our Ewing Bank 910 field.

(4) Primarily related to our Ship Shoal 028 field and our Green Canyon 859 field (Heidelberg).

(5) Primarily related to conveyance of interest in properties related to the JV Drilling Program.

(6) 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.

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

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

(9) 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.

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

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

(12) We believe that we will be able to develop all but 2.3 MMBoe (approximately 19%) of the total of 12.2 MMBoe reserves classified as proved undeveloped ("PUDs") at December 31, 2020, within five years from the date such reserves 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 2022 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, | | | |
|---|---|---|---|---|
| | 2020 | 2019 | 2018 | 2017 |
| Oil - per barrel | $ 37.78 | $ 58.11 | $ 65.21 | $ 46.58 |
| NGLs per barrel | 10.29 | 18.72 | 29.73 | 22.65 |
| Natural gas per Mcf | 2.05 | 2.63 | 3.13 | 2.86 |

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 2021 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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Standardized Measure of Discounted Future Net Cash Flows** | | | |
| Future cash inflows | $ 2,561.2 | $ 4,153.8 | $ 3,500.9 |
| Future costs: | | | |
| Production | (1,257.4) | (1,901.1) | (958.5) |
| Development and abandonment | (707.4) | (794.7) | (628.3) |
| Income taxes | (60.5) | (170.5) | (293.9) |
| Future net cash inflows before 10% discount | 535.9 | 1,287.5 | 1,620.2 |
| 10% annual discount factor | (42.2) | (300.6) | (553.2) |
| Total | $ 493.7 | $ 986.9 | $ 1,067.0 |

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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Changes in Standardized Measure** | | | |
| Standardized measure, beginning of year | $ 986.9 | $ 1,067.0 | $ 740.6 |
| Increases (decreases): | | | |
| Sales and transfers of oil and gas produced, net of production costs | (168.6) | (315.8) | (398.1) |
| Net changes in price, net of future production costs | (503.7) | (376.4) | 571.5 |
| Extensions and discoveries, net of future production and development costs | 2.8 | 27.0 | 53.6 |
| Changes in estimated future development costs | (15.9) | (6.0) | (114.7) |
| Previously estimated development costs incurred | 1.4 | 19.3 | 48.4 |
| Revisions of quantity estimates | (65.2) | 116.4 | 307.6 |
| Accretion of discount | 111.8 | 107.4 | 50.5 |
| Net change in income taxes | 87.7 | 62.9 | (133.4) |
| Purchases of reserves in-place | 44.6 | 298.3 | 27.8 |
| Sales of reserves in-place | — | — | (54.1) |
| Changes in production rates due to timing and other | 11.9 | (13.2) | (32.7) |
| Net (decrease) increase | (493.2) | (80.1) | 326.4 |
| Standardized measure, end of year | $ 493.7 | $ 986.9 | $ 1,067.0 |

**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, 2020 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, 2020, 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, 2020, 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, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

None.

## 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 and to the information set forth following Item 3 of this report.

**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 | Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103)) |
| 3.3 | 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)) |
| 3.4 | Form of Certificate of Amendment No. 2 to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2016 (File No. 001-32414)) |
| 3.5 | 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)) |
| 4.1 | Specimen Common Stock Certificate (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103)) |
| 4.2 | 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. (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)) |
| 4.3 | Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended (Incorporated by reference to Exhibit 4.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2019 (File No. 001-32414)). |
| 10.1* | 2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103)) |
| 10.2* | First Amendment to the 2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Appendix A of the Company's Definitive Proxy Statement, filed March 26, 2020 (File No. 001-32414)) |

| | |
|---|---|
| 10.3* | 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 | Purchase Agreement dated October 5, 2018 by and among W&T Offshore, Inc., W&T Energy VI, LLC, W&T Energy VII, LLC and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers named therein. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on October 11, 2018 (File No. 001-32414)) |
| 10.12 | 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)) |
| 10.13 | 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)) |

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| 10.14 | 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)) |
| 10.15 | 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)) |
| 10.16 | 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). |
| 10.17 | 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). |
| 10.18 | 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)). |
| 10.19** | 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. |
| 10.20 | 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)) |
| 10.21* | Form of 2016 Executive Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.10 of the Company's Quarterly Report on Form 10-Q, filed November 3, 2016 (File No. 001-32414)) |
| 10.22* | Form of 2017 Executive Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q, filed May 4, 2017 (File No. 001-32414)) |
| 10.23* | Form of Executive Annual Incentive Agreement for Fiscal 2018 (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed November 1, 2018 (File No. 001-32414)) |
| 10.24* | Form of 2018 Executive Long Term Incentive Agreement (Incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q, filed November 1, 2018 (File No. 001-32414)) |
| 10.25 | Form of Executive Annual Incentive Award Agreement for Fiscal Year 2019 (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q filed October 31, 2019 (File No. 001-32414)). |

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| 10.26* | Form of 2019 Executive Long Term Incentive Plan Agreement (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q filed October 31, 2019 (File No. 001-32414)). |
| 10.27 | 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 XBRL and contained in Exhibit 101) |

* Management Contract or Compensatory Plan or Arrangement.
** Filed or furnished herewith.

## 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 4, 2021.

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 4, 2021.

| | |
|---|---|
| /s/ TRACY W. KROHN<br>**Tracy W. Krohn** | Chairman, Chief Executive Officer, President and Director<br>(Principal Executive Officer) |
| /s/ JANET YANG<br>**Janet Yang** | Executive Vice President and Chief Financial Officer<br>(Principal Financial and Accounting Officer) |
| /s/ VIRGINIA BOULET<br>**Virginia Boulet** | Director |
| /s/ STUART B. KATZ<br>**Stuart B. Katz** | Director |
| /s/ S. JAMES NELSON, JR<br>**S. James Nelson, Jr.** | Director |
| /s/ B. FRANK STANLEY<br>**B. Frank Stanley** | Director |

**Exhibit 10.19**

# FOURTH AMENDMENT TO SIXTH AMENDED AND RESTATED CREDIT AGREEMENT

**THIS FOURTH AMENDMENT TO SIXTH AMENDED AND RESTATED CREDIT AGREEMENT** (herein called this "**Fourth Amendment**"), dated as of July 24, 2020 (the "**Effective Date**"), is entered into by and among W&T OFFSHORE, INC., a Texas corporation, as the borrower (the "**Borrower**"), the Guarantor Subsidiaries party hereto, the various financial institutions parties hereto, as Lenders, TORONTO DOMINION (TEXAS) LLC, individually and as agent (in such capacity together with any successors thereto, the "**Administrative Agent**") for the Lenders, and the issuers of letters of credit parties hereto, as issuers (collectively, the "**Issuers**").

## WITNESSETH

**WHEREAS**, the Borrower, the lenders party thereto (collectively, the "**Lenders**"), the Administrative Agent, the Issuers and the other parties thereto have heretofore executed the Sixth Amended and Restated Credit Agreement, dated as of October 18, 2018 (as amended, supplemented, amended and restated or otherwise modified from time to time, the "**Credit Agreement**"); and

**WHEREAS**, the parties hereto hereby further intend to amend certain provisions of the Credit Agreement, in each case on the terms and conditions set forth herein.

**NOW, THEREFORE**, in consideration of the premises and the mutual agreements herein contained, the undersigned hereby agree as follows:

1. Definitions. Capitalized terms used herein (including in the Recitals hereto) but not defined herein, shall have the meanings as given them in the Credit Agreement, unless the context otherwise requires.

2. Amendments to Credit Agreement. (a) Effective as of the Fourth Amendment Effective Date (as defined below), the definition of Approved Counterparty in Section 1.1 of the Credit Agreement is hereby amended and restated in its entirety to the following:

"Approved Counterparty" means any counterparty to a Hedging Contract with the Borrower or a Restricted Subsidiary that (a) is a Lender or an Affiliate of a Lender, (b) was a Lender or an Affiliate of a Lender at the time such Hedging Contract was consummated, ( c) is listed on Schedule 1 as an Approved Counterparty to the extent such Hedging Contract was in existence on the Closing Date or ( d) is any other Person designated by the Borrower in writing to the Administrative Agent (a "Designated Approved Counterparty"); *provided* that the Borrower shall provide written notice to the Administrative Agent within three (3) Business Days after entering into any Hedging Contract or transaction under a Hedging Contract with any Designated Approved Counterparty, which written notice shall include specific details regarding such Hedging Contract and such transaction and shall state that (i) such Hedging Contract and such transaction has been consummated and identify the Designated Approved Counterparty party thereto, (ii) prior to entering into such Hedging Contract or such transaction, the Borrower offered such transaction to at least two Lenders ( or their Affiliates) that are active in the oil and gas commodity hedging business and such Lenders ( or their Affiliates) do not, as determined in the sole discretion of the Borrower, provide terms that are as good or better as the terms of such transaction to the Borrower and its Restricted Subsidiaries, (iii) such Designated Approved Counterparty has ( or the credit support provider of such Person has), at the time of entry into the applicable Hedging Contract, a long term senior unsecured debt rating, an issuer credit rating, a corporate credit rating, a corporate family rating. a counterparty credit rating, a counterparty risk rating, or any similar type of rating of A- or better from S&P (or its equivalent) or A3 or better from Moody's (or its equivalent) and (iv) such Designated Approved Counterparty has agreed to be bound by Articles IX and X of this Agreement as if it were a Lender.

(b) Effective as of the Fourth Amendment Effective Date, Section 9.12 of the Credit Agreement is hereby amended by adding the following sentence at the end thereof:

Each Lender, each Issuer and each other Lender Party hereby (i) authorizes the Administrative Agent to execute, deliver, and perform on its behalf, an intercreditor agreement in customary form as reasonably determined by the Administrative Agent, together with any amendments, modifications, supplements, and joinders thereto, with each Designated Approved Counterparty providing that amounts received in respect of the exercise of remedies under the Loan Documents shall be applied to Obligations in respect of such Designated Approved Counterparty's Hedging Contract in the order provided in Section 3.1(b) of the Credit Agreement and (ii) understands, acknowledges and agrees that at all times following the execution and delivery of such intercreditor agreement such Lender, Issuer and other Lender Party (and each of their respective successors and assigns) shall be bound by the terms thereof.

3. Representations and Warranties. The Borrower hereby represents and warrants that after giving effect hereto:

(a) the representations and warranties of the Borrower and its Restricted Subsidiaries contained in the Loan Documents (as amended or waived hereby) are true and correct in all material respects (unless such representation or warranty is qualified by materiality, in which event such representation or warranty shall be true and correct in all respects) on and as of the Fourth Amendment Effective Date, other than those representations and warranties that expressly relate solely to a specific earlier date, which shall remain correct in all material respects as of such earlier date (unless such representation or warranty is qualified by materiality, in which event such representation or warranty is true and correct in all respects as of such earlier date);

(b) the execution, delivery and performance by the Borrower and its Restricted Subsidiaries of this Fourth Amendment are within their corporate or limited liability company powers, have been duly authorized by all necessary action, require, in respect of any of them, no action by or in respect of, or filing with, any governmental authority which has not been performed or obtained and do not contravene, or constitute a default under, any provision of Law or regulation or the articles of incorporation or the bylaws of any of them or any agreement, judgment, injunction, order, decree or other instrument binding upon the Borrower or its Restricted Subsidiaries or result in the creation or imposition of any Lien on any asset of any of them except as contemplated by the Loan Documents other than, in each case, as would not reasonably be expected to cause or result in a Material Adverse Change;

(c) the execution, delivery and performance by the Borrower and its Restricted Subsidiaries of this Fourth Amendment constitutes the legal, valid and binding obligation of each of them enforceable against them in accordance with its terms except as such enforcement may be limited by bankruptcy, insolvency or similar Laws of general application relating to enforcement of creditors' rights; and

(d) no Default or Event of Default has occurred and is continuing.

4. Conditions to Effectiveness of Amendments. The amendments in this Fourth Amendment shall each be effective on the date on which all of the following conditions in this Section 4 of this Fourth Amendment are satisfied (such date, the "**Fourth Amendment Effective Date**").

(a) The Administrative Agent shall have received counterparts of this Fourth Amendment duly executed by the Borrower, the Guarantor Subsidiaries, the Administrative Agent and the Required Lenders.

(b) The Administrative Agent shall have received all fees and expenses to the extent invoiced at least one (1) Business Day prior to the Fourth Amendment Effective Date.

5. Redetermination of Borrowing Base. This Fourth Amendment shall be deemed to be an amendment to the Credit Agreement effective as of the dates set forth herein, and the Credit Agreement, as hereby amended, is hereby ratified, approved and confirmed in each and every respect. The Borrower and each Guarantor Subsidiary hereby ratifies, approves and confirms in every respect all the terms, provisions, conditions and obligations of the Loan Documents (including, without limitation, all Security Documents) to which it is a party. All references to the Credit Agreement in any Loan Document or in any other document, instrument, agreement or writing shall hereafter be deemed to refer to the Credit Agreement as hereby amended. This Fourth Amendment is a Loan Document.

6. Costs And Expenses. As provided in Section 10.4 of the Credit Agreement, the Borrower agrees to reimburse the Administrative Agent for all reasonable costs and expenses incurred by or on behalf of the Administrative Agent (including attorneys' fees, consultants' fees and engineering fees, travel costs and miscellaneous expenses) in connection with this Fourth Amendment and any other agreements, documents, instruments, releases, terminations or other collateral instruments delivered by the Administrative Agent in connection with this Fourth Amendment.

**7. GOVERNING LAW. THIS FOURTH AMENDMENT SHALL BE DEEMED A CONTRACT AND INSTRUMENT MADE UNDER THE LAWS OF THE STATE OF NEW YORK AND SHALL BE CONSTRUED AND ENFORCED IN ACCORDANCE WITH AND GOVERNED BY THE LAWS OF THE STATE OF NEW YORK AND THE LAWS OF THE UNITED STATES OF AMERICA, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW.**

8. Severability. If any term or provision of this Fourth Amendment shall be determined to be illegal or unenforceable all other terms and provisions of this Fourth Amendment shall nevertheless remain effective and shall be enforced to the fullest extent permitted by applicable Law.

9. Counterparts. This Fourth Amendment may be separately executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same agreement. Any signature hereto delivered by a party by facsimile or electronic transmission shall be deemed to be an original signature hereto.

10. Successors and Assigns. This Fourth Amendment shall be binding upon the Borrower and its successors and permitted assigns and shall inure, together with all rights and remedies of each Lender Party hereunder, to the benefit of each Lender Party and its successors, transferees and assigns.

13. No Waiver. The execution, delivery and effectiveness of this Fourth Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of any Lender or the Administrative Agent under any of the Loan Documents, nor constitute a waiver by the Administrative Agent or the Lenders of any Defaults or Events of Default which may exist, which may have occurred prior to the date of the effectiveness of this Fourth Amendment or which may occur in the future under the Credit Agreement and/or the other Loan Documents.

*(The remainder of this page is intentionally left blank.)*

**IN WITNESS WHEREOF**, the parties hereto have caused this Fourth Amendment to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

BORROWER:

W&T OFFSHORE, INC.

By: /s/ Janet Yang
Name: Janet Yang
Title: Executive Vice President and Chief Financial Officer

TORONTO DOMINION (TEXAS) LLC, as Administrative Agent

By: /s/ Hughroy Enniss
Name: Hughroy Ennis
Title: Authorized Signatory

THE TORONTO-DOMINION BANK, NEW YORK BRANCH, as Lender

By: /s/ Hughroy Enniss
Name: Hughroy Ennis
Title: Authorized Signatory

THE TORONTO-DOMINION BANK, NEW YORK BRANCH, as Issuer

By: /s/ Hughroy Enniss
Name: Hughroy Ennis
Title: Authorized Signatory

MORGAN STANLEY BANK, N.A., as Lender

By: /s/ Marisa B. Moss
Name: Marisa B. Moss
Title: Authorized Signatory

SOCIÉTÉ GENERALE, as Lender

By: /s/ Barbara Paulsen
Name: Barbara Paulsen
Title: Managing Director

ZIONS BANCORPORATION, N.A. DBA AMEGY BANK. as Lender

By: /s/ Brad Ellis
Name: Brad Ellis
Title: Senior Vice President

ABN AMRO CAPITAL USA LLC, as Lender

By: /s/ Darrell Holley
Name: Darrell Holley
Title: Managing Director

By: /s/ Beth Johnson
Name: Beth Johnson
Title: Executive Director

ACKNOWLEDGED AND ACCEPTED BY:

W & T ENERGY VI, LLC

By: /s/ Janet Yang
Name: Janet Yang
Title: Executive Vice President and Chief Financial Officer

W & T ENERGY VII, LLC

By: /s/ Janet Yang
Name: Janet Yang
Title: Executive Vice President and Chief Financial Officer

**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** |
|---|---|---|
| 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. 333-224410) 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 4, 2021, 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, 2020.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 4, 2021

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 4, 2021, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated February 11, 2021, 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, 2020", and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2016, 2017, 2018, and 2019. We further consent to the incorporation by reference of information contained in our report dated February 11, 2021, in the Registration Statements (Form S-3 Nos. 333-224410 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 4, 2021

**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 4, 2021 | /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 4, 2021

/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, 2020 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 4, 2021 | /s/ Tracy W. Krohn |
| | Tracy W. Krohn<br>Chairman, Chief Executive Officer, President and Director<br>(Principal Executive Officer) |
| Date: March 4, 2021 | /s/ Janet Yang |
| | Janet Yang<br>Executive Vice President and Chief Financial Officer<br>(Principal Financial and Accounting Officer) |

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



February 11, 2021

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, 2020, 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, 2020, to be:

| | Net Reserves | | | Future Net Revenue(1) (M$) | |
|---|---|---|---|---|---|
| Category | Oil (MBBL) | NGL (MBBL) | Gas (MMCF) | Total | Present Worth at 10% |
| Proved Developed Producing | 19,390.2 | 15,613.9 | 510,393.6 | 816,921.6 | 572,995.0 |
| Proved Developed Non-Producing | 4,598.1 | 921.4 | 39,782.5 | 129,441.3 | 73,653.6 |
| Proved Undeveloped | 8,207.8 | 882.9 | 19,092.8 | 180,506.9 | 94,227.6 |
| Total Proved | 32,196.1 | 17,358.2 | 569,269.0 | 1,126,869.8 | 740,876.3 |

(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 as-of date 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 2020. For oil and NGL volumes, the average West Texas Intermediate spot price of $39.54 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $1.985 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 $37.78 per barrel of oil, $10.29 per barrel of NGL, and $2.049 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: February 11, 2021

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

Date Signed: February 11, 2021

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.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

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

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
*(1)* Lifting the oil and gas to the surface; and
*(2)* Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

**DEFINITIONS OF OIL AND GAS RESERVES**

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

*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

**DEFINITIONS OF OIL AND GAS RESERVES**
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.*
*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.*

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.