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, 2018

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)**
Nine Greenway Plaza, Suite 300 **Houston, Texas**	**77046-0908**
(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	Name of Each Exchange on Which Registered
Common Stock, par value $0.00001	**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 and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 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 $659,712,000 based on the closing sale price of $7.15 per share as reported by the New York Stock Exchange on June 29, 2018.

The number of shares of the registrant's common stock outstanding on February 28, 2019 was 140,644,033.

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.
TABLE OF CONTENTS

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.

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.

We have grown through acquisitions, exploration and development and currently hold working interests in 48 offshore fields in federal and state waters (47 producing and one field capable of producing). We currently have under lease approximately 720,000 gross acres (390,000 net acres) spanning across the Outer Continental Shelf ("OCS") off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 515,000 gross acres on the conventional shelf and approximately 205,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 123 offshore structures, 81 of which are located in fields that we operate. We currently own interest in 201 productive wells, 135 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 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.

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 2018, average commodity realized prices improved from those we experienced during 2017 and 2016. Our margins in 2018 improved from 2017 and 2016 levels, and were approximately the margin levels achieved prior to 2015. We measure margins using adjusted earnings before interest, income taxes, depreciation and amortization, ("Adjusted EBITDA") as a percent of revenue, which is a not a measurement under generally accepted accounting principles ("GAAP"). We have historically increased our reserves and production through acquisitions, our drilling programs, and other projects that optimize production on existing wells. While our production decreased 8.5% in 2018 from the prior year, we added 23.1 million barrels of oil equivalent ("MMBoe") of proved reserves in 2018, replacing 174% of production. (MMBoe was computed on an equivalency ratio as described below.) The 13.2% net increase in proved reserves year-over-year is a result of successful drilling, technical revisions driven by improved well performance, recompletion and workover efforts, and improved commodity prices. During 2018, we completed one well which had reached target depth in 2017, and drilled and completed five additional wells which began producing during 2018. One of these wells, the Viosca Knoll 823 A-12 BP2, is currently offline and we are evaluating methods by which to enhance production at that well.

The Gulf of Mexico is an area where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid return on our invested capital. We have leveraged our experience in the conventional shelf (water depths of less than 500 feet) to develop higher impact capital projects in the Gulf of Mexico in both the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet and water depths of less than 500 feet). 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. The investment associated with drilling an offshore well and future development of an offshore project principally depends upon water depth, the depth of the well, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive than those on the conventional shelf. During 2018, we participated in the drilling and completion of three deepwater wells, and in 2016, we participated in the completion of one deepwater well.

During 2018, 2017 and 2016, our production volumes from deepwater fields were over 40% of our production. One of our larger deepwater fields is the Big Bend field, which commenced production in late 2015. Over 90% of our reserves in this field are composed of oil and NGLs on a barrel of oil equivalent ("Boe") basis (computed on an equivalency ratio described below). As of December 31, 2018, the Big Bend field was in our top ten fields based on reserves, net to our interest, on a Boe basis.

We generally sell our crude oil, NGLs and natural gas at the wellhead at current market prices or transport our production to "pooling points" where it is sold. We are required to pay gathering and transportation costs with respect to a majority of our products. Our products are marketed several different ways depending upon a number of factors, including the availability of purchasers at the wellhead, the availability and cost of pipelines near the well or related production platforms, the availability of third-party processing capacity, market prices, pipeline constraints and operational flexibility.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum consultants, our total proved reserves at December 31, 2018 were 84.0 MMBoe compared to 74.2 MMBoe as of December 31, 2017. Approximately 64% of our proved reserves as of December 31, 2018 were classified as proved developed producing, 16% as proved developed non-producing and 20% as proved undeveloped. Classified by product, our proved reserves at December 31, 2018 were 46% crude oil, 12% NGLs and 42% natural gas. These percentages and other energy-equivalent measurements stated in this Form 10-K were determined using the industry standard energy-equivalent ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude 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 significantly. Our total proved reserves had an estimated present value of future net revenues discounted at 10% ("PV-10") of $1,439.8 million before consideration of cash outflows related to asset retirement obligations ("ARO"). Our PV-10 after considering future cash outflows related to ARO was $1,260.5 million, and our standardized measure of discounted future cash flows was $1,067.0 million as of December 31, 2018. Neither PV-10 nor PV-10 after ARO is a financial measure defined under GAAP. For additional information about our proved reserves and a reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 in this Form 10-K.

To provide additional financial flexibility, we created a drilling joint venture program with private investors during 2018 (the "JV Drilling Program") and initiated drilling on several of the projects. The JV Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in 14 drilling projects. It also allows more projects to be taken on which leverages our capital expenditures and diversifies our risk. During 2018, there were four wells in the JV Drilling Program that came on production. In addition, as of December 31, 2018, one well was being drilled and one well was in the completion stage. The current plan is to complete the 14 projects within a three-year period, but is subject to change as needed with any required approval of the other investors. 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 JV Drilling Program.

In October 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, 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. Concurrently, we renewed our credit facility by entering into the Sixth Amended and Restated Credit Agreement (the "Credit Agreement"), which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million. The borrowing base is subject to scheduled semi-annual redeterminations 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 Credit Agreement replaced the Fifth Amended and Restated Credit Agreement (the "Prior Credit Agreement"). Funds from the Senior Second Lien Notes, cash on hand and borrowings under the Credit Agreement were used to repurchase and retire, repay or redeem all of our previously outstanding secured senior notes and secured term loans. 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". The Refinancing Transaction reduced our debt levels, extended the maturities for our fixed rate debt and provided increased liquidity under the Credit Agreement through October 2022. 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 of the transaction and the new debt instruments.

Our capital expenditure budget for 2019 of approximately $120.0 million is composed of select shelf and deepwater projects that, assuming success, would be placed on production within a few months after completion. Our 2019 plans also include spending $25.0 million for ARO. Based upon current price and production expectations for 2019, we believe that our cash flows from operating activities and cash on hand will be sufficient to fund our operations through year-end 2019 and build available cash balances; however, future cash flows are subject to a number of variables and additional capital expenditures may be required to more fully develop our properties. We are also currently evaluating various acquisition opportunities, which, if successful, may increase our capital requirements in 2019 and beyond.

We continue to closely monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2019 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.

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;
- 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. Over time, we expect to de-lever through excess free cash flow generated by organic growth and accretive acquisitions.

Competition

The oil and natural gas industry is highly competitive. 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 2018, approximately 30% of our revenues were to Shell Trading (US) Co., 20% to BP Products North America and 14% to Vitol Inc., with no other customer comprising greater than 10% of our 2018 revenues. Due to the free trading nature of the oil and natural gas markets in the Gulf of Mexico, we do not believe the loss of a single customer or a few customers would materially affect our ability to sell our production. We do not have any agreements which obligate us to deliver material quantities to third parties.

Regulation

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 nonprice 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. 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.

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 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"). NTL #2016-N01 became effective in September 2016, but the BOEM has since extended indefinitely the start date for implementation. This extension currently remains in effect; however, the BOEM reserved the right to re-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. During late 2015, the BSEE issued a final rule requiring lessees to submit summaries of actual expenditures for decommissioning of wells, platforms, and other facilities required under the BSEE's existing regulations. The BSEE has reported that it will use 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 Office of Natural Resources Revenue (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 results 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.

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 producing operations, the amounts and types of materials that may be released into the environment, the discharge and disposal of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments 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. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict joint and several liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent and address pollution, such as the closure of inactive oil and gas waste pits and the plugging of abandoned wells. 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 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. From time to time, however, various environmental groups have challenged the Environmental Protection Agency’s (“EPA”) exemption of certain oil and gas wastes from RCRA. For example, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency’s failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA must propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Standards have been developed under RCRA and/or state laws for worker protection; treatment, storage, and disposal of Naturally Occurring Radioactive Materials (“NORM”) and NORM waste; management of NORM-contaminated waste piles, containers and tanks; and limitations on the relinquishment of NORM contaminated land for unrestricted use. Historically, we have not incurred any material expenditures in connection with our compliance with 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. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either “attainment/unclassifiable,” “unclassifiable” or “non-attainment.”

In the absence of federal legislation limiting greenhouse gases (“GHG”) emissions, 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 June 2016, the EPA published a final rule establishing new source performance standards 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 would apply 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. However, in June 2017, the EPA published a proposed rule to stay certain portions of the 2016 rule for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018, the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified offshore production sources.

Water Discharges. The primary federal law for oil spill liability is the Oil Pollution Act (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 a release of oil and natural resource 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 million and $150 million for companies operating on the OCS. We are currently required to demonstrate, on an annual basis, that we have ready access to $150 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 may have significant costs. Obtaining permits has the potential to delay, restrict or cancel the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur 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. 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. During 2017, we reached an agreement with the various governmental agencies to remove the topside structure on our non-producing platform located in a National Marine Sanctuary in the U.S. Gulf of Mexico and leave the bottom of the platform structure below the water line in place. The project was completed during 2018 and allows the marine growth attached to and around the structure to remain and continue to grow. As a result, we are subject to additional federal regulation, including regulations issued by the National Oceanic and Atmospheric Administration. Unique regulations related to operations in a sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels.

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 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 permits required for our various operations are subject to revocation, modification and renewal by issuing authorities.

Financial Information

We operate our business as a single segment. See *Selected Financial Data* under Part II, Item 6 and *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.

Employees

As of December 31, 2018, we employed 282 people. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Additional Information

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., Nine Greenway Plaza, Suite 300, Houston, Texas 77046 or by calling (713) 297-8024. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. 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.

Risks Relating to Our Industry, Our Business and Our Financial Condition

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 could adversely affect our business, financial condition, cash flow, liquidity or results of operations and could affect our ability to fund future capital expenditures needed to find and replace reserves, meet our financial commitments and to implement our business strategy.

The price we receive for our 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. Crude oil, NGLs and natural gas are commodities and historically have been subject to wide price fluctuations, sometimes in response to minor changes in supply and demand. These markets for crude oil, NGLs and natural gas have been volatile and will likely continue to be volatile in the future. Although average prices increased for these commodities during 2018 compared to the last three years, prices are substantially below 2014 and 2013 levels. Oil and NGL prices, however, declined substantially in the fourth quarter 2018. The prices we receive for our production and the volume of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for crude oil, NGLs and natural gas;
- the actions of the Organization of Petroleum Exporting Countries ("OPEC") and certain other countries;
- the price and quantity of imports of foreign crude oil, NGLs, natural gas and liquefied natural gas;
- acts of war, terrorism or political instability in oil producing countries;
- national and global economic conditions;
- domestic and foreign governmental regulations;
- political conditions and events, including embargoes, affecting oil-producing activities;
- the level of domestic oil and natural gas exploration and production activities;
- the level of global oil and natural gas exploration and production activities;
- the level of global crude oil, NGLs and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- the price, availability and acceptance of alternative fuels; and
- geographic differences in pricing.

Low prices for our products reduce our profitability and can materially and adversely affect our future business, financial condition, results of operations, liquidity, ability to finance planned capital expenditures, ability to fund our ARO, ability to repay any borrowings per our debt agreements, to secure supplemental bonding, to secure collateral for such bonding, if required, and to meet our other financial obligations.

The borrowing base under our Credit Agreement may be reduced by our lenders.

Availability of borrowings and letters of credit under our Credit Agreement is determined by establishment of a borrowing base, which is periodically redetermined during the year based on our lenders' review of crude oil, NGLs and natural gas prices and on our proved reserves. In October 2018, the borrowing base was increased from $150.0 million to $250.0 million. The borrowing base is subject to scheduled semi-annual redeterminations to occur on or before May 15 and November 14 each year and certain additional redeterminations that may be requested at the discretion of either the lenders or the Company. The borrowing base could be reduced in the future as a result of the lower commodity prices, our lenders' outlook for future prices or our inability to replace reserves as a result of constrained capital spending. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base; such excess or deficiency is required to be repaid within 90 days in three equal monthly payments. In addition to the borrowing base limitation, the Credit Agreement limits our ability to incur additional indebtedness if we cannot comply with specified financial covenants and ratios.

We may not have the financial resources in the future to repay an excess or deficiency resulting from a borrowing base redetermination as required under our Credit Agreement, which could result in an event of default. Additionally, a material reduction of our current cash position could substantially limit our ability to comply with other cash needs, such as collateral needs for existing or additional supplemental surety bonds or other financial assurances issued to the BOEM for our decommissioning obligations. Further, the failure to repay an excess or deficiency that may result from a borrowing base redetermination under our Credit Agreement may result in a cross-default under our other debt agreement. If crude oil, NGLs and natural gas prices fall back to the levels experienced in 2016, this would adversely affect our cash flow, which could result in reductions in our borrowing base, adversely affect prospects for alternative credit availability or affect our ability to satisfy our covenants and ratios under our Credit Agreement.

We have a significant amount of indebtedness. 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, 2018, we had $646.0 million principal amount of indebtedness outstanding, all of which was secured, and additionally had $9.6 million of letters of credit obligations outstanding. Our borrowing availability on our Credit Agreement was $219.4 million as of December 31, 2018, as we had $21.0 million borrowings and the letters of credit obligations outstanding. Our leverage and debt service obligations could:

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

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. Substantially all of our oil, NGLs and natural gas properties are pledged as collateral under our Credit Agreement and are also pledged as collateral on a subordinate basis under our other debt agreement. Lower crude oil, NGLs and natural gas prices in the future would adversely affect our cash flow and could result in reductions in our borrowing base, reduce prospects for alternate credit availability, and affect our ability to satisfy the covenants and ratios under our Credit Agreement. Asset sales may also reduce available collateral and availability under our Credit Agreement. In addition, we cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations.

If we are unable to service our indebtedness and other obligations, we may be required to further refinance all or part of our existing debt, sell assets, reduce capital expenditures, borrow more money or raise equity. We may not be able to further restructure or refinance our debt, reduce capital expenditures, sell assets, borrow more money or raise equity on terms acceptable to us, if at all, or such alternative strategies may yield insufficient funds to make required payments on our indebtedness. In addition, our ability to comply with the financial and other restrictive covenants in our debt instruments is uncertain and will be affected by our future performance and events or circumstances beyond our control. Failure to comply with these covenants would result in an event of default under such indebtedness, the potential acceleration of our obligation to repay outstanding debt and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under our other outstanding indebtedness. Any of the above risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We may be able to incur substantially more debt. This could exacerbate the risks associated with our indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, subject to the terms of our debt agreements. As of December 31, 2018, we had $646.0 million principal amount of secured indebtedness. The components of our indebtedness are:

- $21.0 million outstanding under our Credit Agreement; and
- $625.0 million in aggregate principal amount of the 9.75% Senior Second Lien Notes.

If new debt is added to our current debt levels, the related risks that we face could intensify. Our level of indebtedness may prevent us from engaging in certain transactions that might otherwise be beneficial to us by limiting our ability to obtain additional financing, limiting our flexibility in operating our business or otherwise. In addition, we could be at a competitive disadvantage against other less leveraged competitors that have more cash flow to devote to their business.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions.

The indentures and credit agreements 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 subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of our company;
- engage in transactions with our affiliates;
- maintain certain cash balances;

- pay dividends or make other distributions on capital stock or subordinated 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 other debt instruments.

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

We may be unable to access the equity or debt capital markets to meet our obligations.

Lower crude oil, NGLs and natural gas prices will adversely affect our cash flow and may lead to further reductions in the borrowing base, which could also lead to reduced prospects for alternate credit availability. The capital markets we have historically accessed as an alternative source of equity and debt capital may be constrained. Other capital sources may arise with significantly different terms and conditions. These limitations in the capital markets may affect our ability to grow and limit our ability to replace our reserves of oil and gas.

Our plans for growth may include accessing the equity and debt capital markets. If those markets are unavailable, or if we are unable to access alternative means of financing on acceptable terms, we may be unable to implement all of our drilling and development plans, make acquisitions or otherwise carry out our business strategy, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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.

As of December 31, 2018, we had $646.0 million principal amount of secured indebtedness outstanding. If in the future we default on any, we cannot provide assurance that the proceeds from the sale of the collateral will be sufficient to repay all of our secured debt in full. In addition, we have certain rights to issue or incur additional secured debt, including up to $219.4 million as of December 31, 2018, available for borrowing under our Credit Agreement, 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.

The collateral securing the various issues of our secured debt has not been appraised. The value of the collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers for the collateral. The value of the assets pledged as collateral for our secured debt could be impaired in the future as a result of changing economic conditions, commodity prices, competition or other future trends. Likewise, we cannot provide assurance that the pledged assets will be saleable or, if saleable, that there will not be substantial delays in their liquidation.

In addition, to the extent that third parties hold prior liens, such third parties may have rights and remedies with respect to the property subject to such liens that, if exercised, could adversely affect the value of the collateral securing our secured debt.

With respect to some of the collateral securing our secured 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. We cannot provide assurance that any such required consents, fee payments or filings can be obtained on a timely basis or at all. 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. Therefore, the practical aspect of realizing value from the collateral may, without the appropriate consents, fees and filings, be limited.

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, however, could in the future make demands for additional financial assurances covering our obligations under our properties, which could exceed the Company's capabilities to provide. If the BOEM issues future orders to provide additional surety bonds or other additional financial assurances and 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 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. If additional collateral is required to support surety bond obligations, this collateral would probably 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. 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.

If crude oil, NGLs and natural gas prices decrease from their current levels, we may be required to further write down the carrying values and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we review the carrying value of our oil and natural gas properties quarterly for possible impairment. Impairment of proved properties under our full cost oil and gas accounting method is largely driven by the present value of future net revenues of proved reserves estimated using the SEC mandated 12-month unweighted first-day-of-the-month commodity prices. In addition to commodity prices, impairment assessments of proved properties include the evaluation of development plans, production data, economics and other factors. As crude oil, NGLs and natural gas prices declined in 2015, we incurred impairment charges in each quarter in 2015 totaling $987.2 million for the year. Such write-downs constitute a non-cash charge to earnings. As prices fell further during 2016, we incurred impairment charges in the first three quarters of 2016 which totaled $279.1 million. We did not incur any such write-downs during 2018 or 2017. If prices fall significantly below current levels, this may cause write-downs during 2019 or in future periods. In addition, lower 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 value of our proved reserves.

No assurance can be given that we will not experience additional ceiling test impairments in future periods, which could have a material adverse effect on our results of operations in the periods taken. Also, no assurance can be given that commodity price decreases will not affect our reserve volumes. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview* and *Critical Accounting Policies – Impairment of oil and natural gas properties* under Part II, Item 7 and *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K for additional information on the ceiling test.

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

Current SEC guidance requires that proved undeveloped reserves ("PUDs") may only be classified as such if a development plan has been adopted indicating that they are reasonably certain to be drilled within five years of the date of booking. This rule may limit our potential to book additional PUDs as we pursue our drilling program. If current prices decline, we also may be compelled to postpone the drilling of PUDs until prices recover. If we postpone drilling of PUDs beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped. In addition, if we are unable to demonstrate funding sources for our development plan with reasonable certainty, we may have to write-off all or a portion of our PUDs.

Our PUDs comprised 20% of our total proved reserves as of December 31, 2018 and require additional expenditures and/or activities to convert these into producing reserves. As circumstances change, we cannot provide assurance that all future expenditures will be made and that activities will be entirely successful in converting these reserves into proved producing reserves or PUDs during the time periods we have planned, at the costs we have budgeted, which could result in the write-off of previously recognized proved reserves. We are the operator for substantially all of our PUDs as of December 31, 2018. In the future, however, we could have more of our PUDs in non-operated fields, which may put us in a position of not being able to control the timing of development activities for the non-operated fields.

Relatively short production periods for our Gulf of Mexico properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace those reserves would result in decreasing reserves, production and cash flows over time.

Unless we conduct successful development and exploration activities at sufficient levels or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. 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. Reserves in the Gulf of Mexico generally decline more rapidly than reserves in many other producing regions of the United States. Our independent petroleum consultant estimates that 41% of our total proved reserves will be depleted within three years. As a result, our need to replace reserves and production from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a larger portion of their reserves in areas other than the Gulf of Mexico. We may not be able to develop, find or acquire additional reserves in sufficient quantities to sustain our current production levels or to grow production beyond current levels. 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.

Significant capital expenditures are required to replace our reserves. If we are not able to replace reserves, we will not be able to sustain production at current levels.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful exploration, development or acquisition activities, our proved reserves and production will decline over time. Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures and acquisitions with cash on hand, cash provided by operating activities, securities offerings and bank borrowings. The capital markets we have historically accessed may be constrained because of our leverage and we believe our access to capital markets may be limited in the future. Our capital expenditures in 2018 were equal to the amount spent in 2017 and our capital expenditure budget for 2019 is an increase over the amount spent in 2018. 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 produced reserves more difficult. These limitations in the capital markets and our current capital budget may adversely affect our production levels. We cannot be certain that financing for future capital expenditures will be available if needed, and to the extent required, on acceptable terms. For additional financing risks, see "*–Risks Relating to Our Industry, Our Business and Our Financial Condition*."

Additional deepwater drilling laws, regulations and other restrictions, delays in the processing and approval of drilling permits and exploration, development, oil spill-response and decommissioning plans, and other offshore-related developments in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In recent years, we have expanded our drilling efforts on deepwater projects in the Gulf of Mexico. The BSEE and the BOEM have, over time, imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these 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 are continuing to evaluate aspects of safety and operational performance in the Gulf of Mexico and, as a result, are continuing to develop and implement new, more restrictive requirements. For example, in 2016, the BSEE published a final rule on well control that, among other things, imposes rigorous standards relating to the design, operation and maintenance of blow-out preventers, real-time monitoring of deepwater and high temperature, high pressure drilling activities, and enhanced reporting requirements. In May 2018, however, the BSEE issued a proposed rule to revise these regulations for well control but the May 2018 rule has not been finalized.

In May 2017, the Department of the Interior Secretary issued Order 3350 ("Order 3350") directing the BSEE and the BOEM to reconsider a number of regulatory initiatives governing oil and natural gas exploration in offshore federal waters related to safety, air quality control and performance-related activities. Examples of such regulatory initiatives being reconsidered include NTL #2016-N01, a 2016 proposed rule that would update control of offshore air emissions, and existing rules relating to blow-out preventers and well control. Following completion of their reviews, these agencies are to provide recommendations on whether such regulatory initiatives should continue or be implemented. With regard to NTL #2016-N01, which would bolster supplemental bonding procedures for offshore decommissioning activities, the BOEM has delayed implementation indefinitely as the agency continues to reconsider implementation of the NTL. Regarding the 2016 proposed rulemaking published by BOEM that would update existing air emissions requirements relating to offshore oil and natural gas activity on the OCS, Order 3350 directed the BOEM to immediately cease all activities to promulgate the 2016 proposed rule. Also, with regard to existing rules relating to blow-out preventers and well control, in September 2018, the BSEE published final revisions to its regulations regarding offshore drilling safety equipment, which, among other things, included the removal of the requirement for offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) is operational and functioning as designed in the most extreme conditions.

Notwithstanding Order 3350, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any new laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that impose more stringent or costly operating or decommissioning standards on oil and natural gas operators in the OCS, could restrict, delay or cancel operations, disrupt our operations or increase the risk of leases expiring before exploration and development efforts have been completed due to the time required to develop new technology. Additionally, if left unchanged, the existing, or future, more stringent oil and gas safety and performance-related regulations and other regulatory initiatives imposed by the BOEM and BSEE could result in increased financial assurance requirements and incurrence of associated added costs, limit operational activities in certain areas, or cause us to incur penalties or shut-in production at one or more of our facilities. Also, if material spill incidents were to occur in the future, the United States or other countries, where such an event may occur, could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time 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.

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. The current policy 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 a $150.0 million aggregate limit for all of our other properties, subject to a retention of $30.0 million. Included within the $162.5 million aggregate limit is total loss only ("TLO") coverage on our Mahogany platform, which has no retention.

The occurrence of a significant accident or other event not covered in whole or in part by our insurance could have a material adverse impact on our financial condition and operations. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. In May and June 2018, we entered into our insurance policies covering well control and hurricane damage (described above) and for general liability and pollution. These policies are effective for one year from their respective execution date. These policies reduce, but in no way totally mitigate our risk as we are exposed to amounts for retention and co-insurance, limits on coverage and events that are not insured. Renewal of these policies at a cost commensurate with current premiums is not assured. We also have other smaller per-occurrence retention amounts for various other events. In addition, 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.

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. 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. If OPA is amended to increase the minimum level of financial responsibility, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended, or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

For some risks, we have not obtained insurance as we believe the cost of available insurance is excessive relative to the risks presented. We may take on further risks in the future if we believe the cost is excessive to the risks. The occurrence of a significant event not fully insured or indemnified against 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.

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.

Commodity derivative positions may limit our potential gains.

In order to manage our exposure to price risk in the marketing of our oil and natural gas, we periodically enter into oil and natural gas price commodity derivative positions with respect to a portion of our expected production. During the fourth quarter of 2018, we entered into commodity derivative contracts, most of which will expire in May 2020. We may enter into more contracts in the future. While these commodity derivative positions are intended to reduce the effects of volatile crude oil and natural gas prices, 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:

- our production is less than expected;
- 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.

See *Financial Statements and Supplementary Data– Note 9 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information on derivative transactions.

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 for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay or finance. On the acquisition opportunities made available to us, we compete with other companies in our industry for such properties through a private bidding process, direct negotiations or some combination thereof. Our competitors may have significantly more capital resources and less expensive sources of capital. In addition, they may be able to generate acceptable rates of return from marginal prospects due to their lower costs of capital. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence. Additional requirements imposed on us and our ability to finance such acquisitions may put us at a competitive disadvantage for acquiring properties.

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. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than development costs for wells drilled on the conventional shelf because deepwater drilling requires larger installation equipment, sophisticated sea floor production handling equipment, expensive state-of-the-art platforms and infrastructure investments. Deep shelf development can also be more expensive than conventional shelf projects because deep shelf development requires more drilling days and higher drilling and service costs due to extreme pressure and temperatures associated with greater depths. 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.

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, the BSEE issued an updated NTL reaffirming the obligations of offshore operators to timely abandon and remove idle iron, also known as “decommissioning.” 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. 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 the BOEM’s NTL #2016-N01, if ever fully implemented, 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. While the current implementation timeline has been extended indefinitely, except in certain circumstances where there was a substantial risk of nonperformance of the interest holder’s decommissioning liabilities, this timeline could change at the BOEM’s discretion and the BOEM may re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder’s decommissioning liabilities. Under NTL #2016-N01, the BOEM has given broader interpretation authority to the BOEM’s district personnel, which increases the difficulty in complying with this NTL should it be fully implemented. 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 may impact our liquidity adversely.

We may be obligated to pay costs related to other companies that have filed for bankruptcy or have indicated they are unable to pay their share of costs in joint ownership arrangements.

In our contractual arrangements of joint ownership of oil and natural gas interests with other companies, we are obligated to pay our share of operating, capital and decommissioning costs, and have the right to a share of revenues after royalties and certain other cash inflows. If one of the companies in the arrangement is unable to pay its agreed upon share of costs, generally the other companies in the arrangement are obligated to pay the non-paying company's obligations. Under joint operating agreements among working interest owners, the non-paying company would typically lose the right to future revenues, which would be applied to the non-paying company's share of operating, capital and decommissioning costs. If future revenues are insufficient to defray these additional costs, especially in cases where the well has stopped producing and is being decommissioned, we could be obligated to pay certain costs of the defaulting party. In addition, the liability to the U.S. Government for obligations of lessees under federal oil and gas leases, including obligations for decommissioning costs, is generally joint and several among the various co-owners of the lease, which means that any single owner may be liable to the U.S. Government for the full amount of all lessees' obligations under the lease. In certain circumstances, we also could be liable for decommissioning liabilities on federal oil and gas leases that we previously owned and the assignee to whom we assigned the leases or any future assignee of those leases is bankrupt or unable to pay its decommissioning costs. 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 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. The success and timing of exploration and development activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- unusual or unexpected geological formations;
- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells and such participants' financial resources;
- selection of technology; and
- the rate of production of the reserves.

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

Our development activities may be unsuccessful for many reasons, including adverse weather conditions, cost overruns, equipment shortages, geological issues, technical difficulties and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not assure us that we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells hinder our efforts to replace reserves.

Our oil and natural gas exploration and production activities, including well stimulation and completion activities, involve a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as tropical storms, hurricanes and other adverse weather conditions;
- inability to obtain insurance at reasonable rates;
- failure to receive payment on insurance claims in a timely manner, or for the full amount claimed;
- pipe, cement, subsea well or pipeline failures;
- casing collapses or failures;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations or rock compaction; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, encountering NORM, and discharges of brine, well stimulation and completion fluids, toxic gases, or other pollutants into the surface and subsurface environment.

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. We could also incur substantial losses as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations;
- repairs required to resume operations; and
- loss of reserves.

Offshore operations are also subject to a variety of operating risks related to the marine environment, such as capsizing, collisions and damage or loss from tropical storms, hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Companies that incur environmental liabilities frequently also confront third-party claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site. Despite the “petroleum exclusion” of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may have strict joint and several liability under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

Legislation has been proposed from time to time in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from the RCRA definition of "hazardous wastes." A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could potentially subject such wastes to more stringent handling, disposal and cleanup requirements. Other wastes handled at exploration and production sites or generated in the course of providing well services also may not fall within the RCRA oil and gas wastes exclusion. Stricter standards for waste handling, disposal and cleanup may be imposed on the oil and natural gas industry in the future. Additionally, NORM may contaminate minerals extraction and processing equipment used in the oil and natural gas industry. We may have liability for releases of hazardous substances at our properties by prior owners, operators, other third parties, or at properties we have sold. As a result, we could incur substantial liabilities that could reduce or eliminate funds available for exploration, development and acquisitions or result in the loss of property and equipment.

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. For example, during 2018, net production of approximately 1.6 MMBoe was deferred during 2018 due to pipeline issues, maintenance, well issues and other events; and during 2017, net production of approximately 1.7 MMBoe was deferred due to Hurricane Nate, pipeline issues and other events.

Properties that we acquire may not produce as projected and we may be unable to immediately identify liabilities associated with these properties or obtain protection from sellers of such properties.

Our business strategy includes growing by making acquisitions, which may include acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. Our acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

- acceptable prices for available properties;
- amounts of recoverable reserves;
- estimates of future crude oil, NGLs and natural gas prices;
- estimates of future exploratory, development and operating costs;
- estimates of the costs and timing of decommissioning, including plugging and abandonment; and
- estimates of potential environmental and other liabilities.

Our assessment of the acquired properties will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we have historically not physically inspected every well, platform or pipeline. Even if we had physically inspected each of these, our inspections may not have revealed structural and environmental problems, such as pipeline corrosion, well bore issues or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities associated with such risks. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may encounter difficulties integrating the operations of newly acquired oil and natural gas properties or businesses.

Increasing our reserve base through acquisitions has historically been an important part of our business strategy. We may encounter difficulties integrating the operations of newly acquired oil and natural gas properties or businesses. In particular, we may face significant challenges in consolidating functions and integrating procedures, personnel and operations in an effective manner. The failure to successfully integrate such properties or businesses into our business may adversely affect our business and results of operations. Any acquisition we make may involve numerous risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets before our acquisition;
- our lack of drilling history in the geographic areas in which the acquired business operates;
- customer or key employee loss from the acquired business;
- increased administration of new personnel;
- additional costs due to increased scope and complexity of our operations; and
- potential disruption of our ongoing business.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties in our primary operating region or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as with acquisitions within our primary operating region. We may not be successful in addressing these risks or any other problems encountered in connection with any acquisition we may make.

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, 2018. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities*, under Part II, Item 7 for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in *Business* under Part I, Item 1, *Properties* under Part I, Item 2 and *Financial Statements and Supplementary Data – Note 20 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K.

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 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. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area 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. We cannot assure that the analysis we perform using data from other wells, more fully explored prospects and/or producing fields will accurately predict the characteristics and potential reserves associated with our drilling prospects. 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.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

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 most cases are owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. 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 or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to 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 and gathering stations. For example, in September 2008, as a result of Hurricane Ike, two of our operated platforms and eight non-operated platforms were toppled and a number of platforms, third-party pipelines and processing facilities upon which we depend to deliver our production to the marketplace were damaged. In 2012, under threat of Hurricane Isaac, we shut in most of our offshore production for a period of 10 to 25 days. Similar shut-ins of lower magnitude occurred in 2013 from Tropical Storm Karen, in 2017 from Hurricane Nate and in 2018 from Hurricane Michael.

In some cases, our wells are tied back to platforms owned by third-parties who do not have an economic interest in our wells and we cannot be assured that such parties will continue to process our oil and natural gas.

Currently, 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, 2018, nine fields, accounting for approximately 0.6 MMBoe (or 4.5%) of our 2018 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. If any of these platform operators ceases to operate their processing equipment, we may be required to shut in the associated wells, construct additional facilities or assume additional liability to re-establish production.

If third-party pipelines connected to our facilities become partially or fully unavailable to transport our crude oil and natural gas or if the prices charged by these third-party pipelines increase, our revenues or costs could be adversely affected.

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. For example, in 2018, various pipelines were shut down at various times causing production deferral of approximately 0.4 MMBoe.

Certain third-party pipelines have submitted or have made plans to submit requests to increase the fees they charge us to use these pipelines. These increased fees could adversely impact our revenues or increase our operating costs, either of which would adversely impact our operating profits, cash flows and reserves.

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. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- 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.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. 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 to or limitations on 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 ONRR's revised interpretations on determining appropriate allowances related to transportation and processing costs for natural gas could cause us to pay substantial amounts in back royalties and in future royalties.

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 for which we had gas processed. In the second quarter of 2015, pursuant to the initiative, the Company received requests from the ONRR for additional data regarding the Company's transportation and processing allowances on natural gas production that was processed through a specific processing plant. The Company also received a preliminary determination notice from the ONRR asserting its preliminary determination that the Company's allocation of certain processing costs and plant fuel use at another processing plant were impermissibly allowed as deductions in the determination of royalties owed under Federal oil and gas leases. The Company has submitted responses covering certain plants and certain time periods and has not yet received responses as to the preliminary determination asserting the reasonableness of its revised allocation methodology of such costs. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under the Company's Federal oil and gas leases for current and prior periods. Through December 31, 2018, we paid $2.7 million 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.

Should we fail to comply with all applicable FERC, CFTC and FTC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations of up to $1.2 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Under the Commodity Exchange Act and regulations promulgated thereunder by the CFTC and under the Energy Independence and Security Act of 2007 and regulations promulgated thereunder by the FERC, the CFTC and FTC have adopted anti-market manipulation rules relating to the prices or futures of commodities. Additional rules and legislation pertaining to those and other matters may be considered or adopted by Congress, the FERC, the CFTC or the FTC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability. See *Business – Regulation* under Part I, Item 1 in this Form 10-K for further description of our regulations.

Climate change legislation or regulations restricting emissions of GHG could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been adopted. The EPA, however, has adopted regulations under the existing CAA to restrict emissions of GHG. For example, the EPA imposes preconstruction and operating permit requirements on certain large stationary sources that are already potential sources of certain other significant pollutant emissions. The EPA also adopted rules requiring the monitoring and reporting of GHG emissions on an annual basis from specified large GHG emission sources in the United States, including onshore and offshore oil and natural gas production facilities. Federal agencies have also begun directly regulating emissions of methane, a GHG, from oil and natural gas operations as described above. Compliance with these rules could result in increased compliance costs on our operations.

State implementation of these revised air emission standards could result in stricter permitting requirements, delay, limit or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHG and a number of states and grouping of states have already taken legal measures to reduce emissions of GHG primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. Also, carbon taxes, and GHG monitoring and reporting programs have been considered. On an international level, the United States is one of numerous nations that prepared an international climate change agreement in Paris, France in December 2015, requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and became effective in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but does include pledges to voluntarily limit or reduce future emissions. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce emissions of GHG could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHG could have an adverse effect on our business, financial condition and results of operations. Additionally, with concerns over GHG emissions, certain non-governmental activists have recently directed their efforts at shifting funding away from companies with energy-related assets, which could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Our offshore operations are particularly at risk from severe climatic events. If any such climate effects were to occur, they could have an adverse effect on our business, financial condition and results of operations. See – *Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.* – under this Item 1A.

Derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Commodity Futures Trading Commission (the "CFTC") has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.

The CFTC has designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply with or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract or swap facility market.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, we could be required to post initial or variation margin, which would impact our liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity price contracts. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Our operations could be adversely impacted by security breaches, including cyber-security breaches, which could affect our production of oil and natural gas or could affect other parts of 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, or acts of vandalism or terrorism. A breach could result in an interruption in our operations, 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, including Tracy W. Krohn, our Founder, Chairman of the Board, Chief Executive Officer and President; Janet Yang, our Executive Vice President and Chief Financial Officer; David M. Bump, our Executive Vice President of Drilling, Completions and Facilities; William J. Williford, our Executive Vice President and General Manager of Gulf of Mexico; Stephen L. Schroeder, our Senior Vice President and Chief Technical Officer; and Shahid A. Ghauri, our Vice President, General Counsel and Corporate Secretary 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.

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

In past years, legislation was proposed that would have made significant changes to U.S. tax laws, including certain U.S. federal income tax provisions currently available to oil and gas companies. Such legislative proposals have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available to us, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The Tax Cuts and Jobs Act ("TCJA") of 2017 modified certain U.S. Federal income tax provisions applicable to corporations for taxable years beginning after 2017. Along with lowering the corporate income tax rate, the TCJA changed certain income tax rules and deductions including cost recovery, limits on the deductions of interest expense, the elimination of the deduction from domestic production activities and utilization of net operating losses. These changes had an impact on our taxation in 2018. The TCJA did not (i) repeal the percentage depletion allowance for oil and gas properties, (ii) eliminate current deductions for intangible drilling and development costs, or (iii) extend the amortization period for certain geological and geophysical expenditures.

Counterparty credit risk may negatively impact the conversion of our accounts receivables to cash.

Substantially all of our accounts receivable result from crude oil, NGLs and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic or other conditions. In recent years, market conditions resulted in downgrades to credit ratings of some of our oil and gas customers and joint interest partners. While we have not experienced collection issues from our customers, we have experienced collection issues from several of our joint interest partners.

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 high initial production rates. At December 31, 2018, the following ten fields accounted for approximately 84% of our proved reserves determined using quantities of proved net reserves on an energy equivalent basis. Deepwater refers to acreage in over 500 feet of water. Our interests in several of our offshore fields are owned by our wholly-owned subsidiary, W & T Energy VI, LLC. The following table provides information for these fields:

Field Name	Field Category	Percent Oil and NGLs of Proved Reserves (1)	2018 Average Daily Equivalent Sales Rate (Boe/d) Gross	2018 Average Daily Equivalent Sales Rate (Boe/d) Net
Ship Shoal 349 (Mahogany)	Shelf	78%	8,156	6,320
Fairway	Shelf	26%	4,640	3,480
Ship Shoal 28	Shelf	31%	350	187
Miss. Canyon 243 (Matterhorn)	Deepwater	80%	954	954
Viosca Knoll 823 (Virgo)	Deepwater	33%	2,499	1,284
Viosca Knoll 783 (Tahoe/SE Tahoe)	Deepwater	29%	3,380	2,273
Main Pass 108	Shelf	17%	3,336	2,640
Ewing Bank 910	Deepwater	68%	3,738	1,764
Miss. Canyon 582 (Medusa)	Deepwater	90%	4,160	624
Miss. Canyon 698 (Big Bend)	Deepwater	94%	14,079	2,288

(1) The percent oil and NGLs of proved reserves was determined using the energy equivalency ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price on an equivalent basis for oil, NGLs and natural gas may differ significantly.

Volume measurements:
Boe/d – barrel of oil equivalent per day

Our Fields

On December 31, 2018, we had two fields of major significance (which we define as having year-end proved reserves of 15% or more of the Company's total proved reserves, calculated on an energy equivalent basis): the Ship Shoal 349 field (Mahogany) located on the conventional shelf in the Gulf of Mexico and the Fairway Field, located in the Mobile Bay area of Alabama, which includes the associated Yellowhammer gas processing plant located onshore in Alabama. Unless indicated otherwise, "drilling" or "drilled" in the field 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 fields:

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 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 one well that is in the JV Drilling Program. Cumulative field production through 2018 is approximately 49.0 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, 2018, 30 wells have been drilled and 25 were successful. Since acquiring an interest and subsequently taking over as operator, we have directly participated in drilling 16 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. Total proved reserves associated with our interest in this field were 32.4 MMBoe at December 31, 2018, 21.6 MMBoe at December 31, 2017 and 19.8 MMBoe at December 31, 2016.

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,		
	2018	2017	2016
Net Sales:			
Oil (MBbls)	1,719	1,896	1,332
NGLs (MBbls)	167	163	159
Natural gas (MMcf)	2,508	2,853	1,871
Total oil equivalent (MBoe)	2,307	2,534	1,802
Total natural gas equivalents (MMcfe)	13,841	15,205	10,812
Average daily equivalent sales (Boe/day)	6,320	6,943	4,924
Average daily equivalent sales (Mcfe/day)	37,920	41,656	29,543
Average realized sales prices:			
Oil ($/Bbl)	$ 62.83	$ 46.64	$ 31.97
NGLs ($/Bbl)	31.14	25.42	17.88
Natural gas ($/Mcf)	3.41	3.16	2.38
Oil equivalent ($/Boe)	52.78	40.08	27.67
Natural gas equivalent ($/Mcfe)	8.80	6.68	4.61
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 4.87	$ 4.30	$ 5.16
Natural gas equivalent ($/Mcfe)	0.81	0.72	0.86

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

Volume measurements:

Bbl – barrel

MBbls – thousand barrels for crude oil, condensate or NGLs

Boe – barrel of oil equivalent

MBoe – thousand barrels of oil equivalent

Mcf – thousand cubic feet

MMcf – million cubic feet

Mcfe – thousand cubic feet of gas equivalent

MMcfe – million cubic feet of gas equivalent

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 2018 is approximately 133.0 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, 2018, 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. Total proved reserves associated with our interest in this field were 12.2 MMBoe at December 31, 2018, 13.2 MMBoe at December 31, 2017 and 13.7 MMBoe at December 31, 2016.

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,		
	2018	2017	2016
Net Sales:			
Oil (MBbls)	9	10	9
NGLs (MBbls)	315	362	400
Natural gas (MMcf)	5,673	6,270	7,817
Total oil equivalent (MBoe)	1,270	1,417	1,712
Total natural gas equivalents (MMcfe)	7,621	8,501	10,272
Average daily equivalent sales (Boe/day)	3,480	3,882	4,678
Average daily equivalent sales (Mcfe/day)	20,880	23,292	28,065
Average realized sales prices:			
Oil ($/Bbl)	$ 66.63	$ 47.65	$ 41.15
NGLs ($/Bbl)	24.93	21.13	16.72
Natural gas ($/Mcf)	3.12	2.93	2.42
Oil equivalent ($/Boe)	24.54	18.68	17.32
Natural gas equivalent ($/Mcfe)	4.09	3.11	2.89
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 9.38	$ 8.46	$ 7.95
Natural gas equivalent ($/Mcfe)	1.56	1.41	1.32

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

Volume measurements:

Bbl – barrel

MBbls – thousand barrels for crude oil, condensate or NGLs

Boe – barrel of oil equivalent

MBoe – thousand barrels of oil equivalent

Mcf – thousand cubic feet

MMcf – million cubic feet

Mcfe – thousand cubic feet of gas equivalent

MMcfe – million cubic feet of gas equivalent

The following is a description of the remainder of our top 10 properties, measured by proved reserves at December 31, 2018, two of which are located on the conventional shelf and six of which are located in the deepwater. We do not believe that individually any of these properties are of major significance (each has proved reserves which comprise less than 15% of our year-end total proved reserves, calculated on a barrel of oil equivalent basis):

Ship Shoal 028: Ship Shoal 028 field is located off the coast of Louisiana, approximately 90 miles southeast of New Orleans, Louisiana in 10 feet of water. The field area covers Ship Shoal Blocks 13, 14, 28, 29, 30, 34 and 35, with 10 active platforms. It was first discovered in 1947 by Kerr-McGee Oil and Gas Corporation ("Kerr-McGee"). We acquired a 67.5% working interest in the field from Kerr-McGee in 2006. Cumulative field production through 2018 is approximately 159.3 MMBoe gross. The field produces from 35 sands trapped by a faulted 3-way closure. The Upper Miocene age sands were deposited in a fluvial deltaic environment and range in depths from 9,500 feet to 18,000 feet. As of December 31, 2018, 64 wells have been drilled, 54 of which have been successful. During December 2018, production from this field, net to our interest, averaged 117 barrels of crude oil per day, 62 barrels of NGLs per day and 2,441 Mcf of natural gas per day, for total production of 586 Boe per day.

Mississippi Canyon 243 Field (Matterhorn). The Mississippi Canyon 243 field is located off the coast of Louisiana, approximately 100 miles southeast of New Orleans, Louisiana in 2,552 feet of water. The field area covers Mississippi Canyon block 243, with a single floating, tension leg production platform. Société Nationale Elf Aquitaine discovered the field in 2002. We acquired a 100% working interest in the field from Total E&P USA Inc. ("Total E&P") in 2010. Cumulative field production through 2018 is approximately 37.7 MMBoe gross. This field is a supra-salt development with 17 productive horizons, with the maximum depth of 9,850 feet. This field also has a successful secondary recovery project with plans for another secondary recovery project. As of December 31, 2018, 30 wells have been drilled, 13 of which have been successful. Since acquiring 100% working interest in this field, we have drilled three wells with a 100% success rate. During December 2018, production from this field, net to our interest, averaged 383 barrels of crude oil per day, 156 barrels of NGLs per day and 2,090 Mcf of natural gas per day, for total production of 888 Boe per day.

Viosca Knoll 823 Field (Virgo). Viosca Knoll 823 field is located off the coast of Louisiana, approximately 125 miles southeast of New Orleans, Louisiana in 1,014 feet of water. The field area covers Viosca Knoll blocks 823 and 822, with a single fixed leg production platform on Viosca Knoll block 823. Total E&P discovered the field in 1997. We acquired a 64% working interest in the field from Total E&P in 2010 and we are the operator of this property. Two completed wells and one well being completed as of December 31, 2018 are in the JV Drilling Program for this field. Cumulative field production through 2018 is approximately 24.6 MMBoe gross. This field is a supra-salt development with 17 productive horizons at depths ranging from 6,632 feet to 13,335 feet. As of December 31, 2018, 16 wells and one sidetrack well have been drilled, 13 of which have been successful. During December 2018, production from this field, net to our interest, averaged 246 barrels of crude oil per day, 213 barrels of NGLs per day and 4,687 Mcf of natural gas per day, for total production of 1,240 Boe per day.

Viosca Knoll 783 Field (Viosca Knoll 783 (Tahoe) and Viosca Knoll 784 (SE Tahoe)). The Viosca Knoll 783 field is located off the coast of Louisiana, approximately 140 miles southeast of New Orleans, Louisiana in 1,500 to 1,700 feet of water. The field area covers Viosca Knoll blocks 783 and 784, with subsea tiebacks to two platforms in Main Pass 252. Shell discovered the Tahoe prospect in 1984 and the SE Tahoe prospect in 1996. We acquired a 70% working interest in the Tahoe lease and a 100% working interest in the SE Tahoe lease from Shell in 2010. We are the operator of these properties. Cumulative field production through 2018 is approximately 102.6 MMBoe gross. The Tahoe prospect is a supra-salt development with two productive horizons at depths ranging to 10,300 feet. The SE Tahoe prospect is also a supra-salt development with one productive horizon at a depth of 9,325 feet. As of December 31, 2018, 16 wells have been drilled at the Tahoe prospect, eight of which have been successful and one successful well has been drilled at the SE Tahoe prospect. During December 2018, production from this field, net to our interest, averaged 84 barrels of crude oil per day, 336 barrels of NGLs per day and 5,994 Mcf of natural gas per day, for total production of 1,419 Boe per day.

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 107, 108 and 109. This field is located off the coast of Louisiana approximately 50 miles east of Venice, Louisiana in 50 feet of water. We acquired our working interests in these blocks, which range from 33% to 100%, in a transaction with Kerr-McGee in 2006 and we are the operator of this field. Cumulative field production through 2018 is approximately 49.7 MMBoe gross. The field produces from a number of low relief, predominantly stratigraphically trapped sands. The productive interval ranges in age from Upper Miocene Big A through Middle Miocene Big Hum. As of December 31, 2018, 48 wells have been drilled in this field, 30 of which were successful. Since acquiring an interest this field, we have directly participated in drilling seven wells with a 100% success rate. During December 2018, production from this field, net to our interest, averaged 187 barrels of crude oil per day, 193 barrels of NGLs per day and 11,993 Mcf of natural gas per day, for total production of 2,380 Boe per day.

Ewing Bank 910. Ewing Bank 910 is located approximately 68 miles off the Louisiana coast in 560 feet of water. The field area covers Ewing Bank blocks 910 and 954, and South Timbalier blocks 320 and 311. Kerr-McGee discovered the field in 1996. We own a 100% working interest in the main field pays, having acquired a 40% working interest from Kerr-McGee in 2006 and the remaining 60% from Petrobras America Inc. in 2014. Our working interest in the producing wells ranges from 10% to 100%. A single production platform is located on Block 910. Cumulative field production through 2018 is approximately 18.8 MMBoe gross. Production occurs from Pliocene and upper Miocene channel/levee sands set up by a combination of stratigraphic and structural traps. Since its discovery, 12 wells have been drilled, 10 of which were successful and one of the successful wells is in the JV Drilling Program. In addition, another well was being drilled as of December 31, 2018 and this well is in the JV Drilling Program. Since acquiring an interest in this field, we have directly participated in drilling four wells with 100% success rate. During December 2018, production from this field, net to our interest, averaged 987 barrels of crude oil per day, 177 barrels of NGLs per day and 3,618 Mcf of natural gas per day, for total production of 1,767 Boe per day.

Mississippi Canyon 582 Field. (Medusa) Mississippi Canyon 582 field is located off the coast of Louisiana, approximately 110 miles south-southeast of New Orleans, Louisiana in 2,200 feet of water. The field area covers Mississippi Canyon blocks 538, 582 and 583. Murphy Oil Corporation discovered the field in 1999 and is the operator. First production commenced in 2003. We acquired a 15% working interest in the field from Callon Petroleum Operating Company in 2013. The Medusa Spar facility is located on Block 582. Cumulative field production through 2018 is approximately 83.7 MMBoe gross. Production occurs from late Miocene to early Pliocene deep water, channel/levee sand reservoirs. Hydrocarbon traps are a combination of both structural and stratigraphic traps. Since its discovery, 15 wells have been drilled, 11 of which were successful. Additional drilling opportunities have been identified and are currently being evaluated. During December 2018, production from this field, net to our interest, averaged 538 barrels of crude oil per day, 30 barrels of NGLs per day and 481 Mcf of natural gas per day, for total production of 648 Boe per day.

Mississippi Canyon 698 Field (Big Bend). Mississippi Canyon 698 is located approximately 160 miles southeast of New Orleans, Louisiana in 7,221 feet of water. The field area covers portions of Mississippi Canyon blocks 697, 698, and 742. We have a 20% working interest, which is operated by Fieldwood Energy LLC. We, along with Noble Energy Inc., discovered the field in 2012. This field is a subsea tieback to the Thunder Hawk production host facility approximately 18 miles to the northwest of the field. Cumulative field production through 2018 is approximately 17.5 MMBoe gross. The field is a supra-salt development with two productive horizons at depths ranging from 14,660 feet to 15,533 feet total vertical depth. Since its discovery, one well has been drilled, which was successful, with the well beginning production in the fourth quarter of 2015. During December 2018, production from this field, net to our interest, averaged 2,105 barrels of crude oil per day, 57 barrels of NGLs per day and 941 Mcf of natural gas per day, for total production of 2,318 Boe per day.

Proved Reserves

Our proved reserves were estimated by 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, 2018 are summarized below and the mix by product was 46% oil, 12% NGLs and 42% natural gas determined using the energy-equivalent ratio noted 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 (3) (In millions)
Proved developed producing	25.4	6.3	133.3	53.9	323.3	64 %	$ 1,061.8
Proved developed non-producing	6.1	1.5	33.5	13.1	78.9	16 %	165.3
Total proved developed	31.5	7.8	166.8	67.0	402.2	80 %	1,227.1
Proved undeveloped	7.6	2.0	43.7	17.0	101.9	20 %	212.7
Total proved	39.1	9.8	210.5	84.0	504.1	100 %	$ 1,439.8

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) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2018 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, 2018. The WTI spot price and the Henry Hub spot price were utilized as the referenced price and after adjusting for quality, transportation, fees, energy content and regional price differentials, the average realized prices were $65.21 per barrel for oil, $29.73 per barrel for NGLs and $3.13 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) Energy equivalents are 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 price for oil and NGLs may differ significantly.

(3) We refer to PV-10 as the present value of estimated future net revenues of 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 and excludes ARO. We have also included PV-10 after ARO below. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate and no inflation of current costs. 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, from 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, 2018
Present value of estimated future net revenues (PV-10)	$ 1,439.8
Present value of estimated ARO, discounted at 10%	(179.3)
PV-10 after ARO	1,260.5
Future income taxes, discounted at 10%	(193.5)
Standardized measure of discounted future net cash flows	$ 1,067.0

Changes in Proved Reserves

Our total proved reserves at December 31, 2018 were 84.0 MMBoe compared to 74.2 MMBoe at December 31, 2017, representing an overall increase of 9.8 MMBoe. Increases from extensions and discoveries were 2.1 MMBoe, positive technical revisions (including increased well performance) were 18.8 MMBoe, increases due to higher commodity prices were estimated to be 2.3 MMBoe and increases related to acquisitions were 3.4 MMBoe. Partially offsetting were decreases for divestitures of 3.5 MMBoe and production of 13.3 MMBoe. See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2018. 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 of December 31, 2018 are calculated based upon SEC mandated 2018 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 2018 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, 2018 included in this Form 10-K was prepared by our independent petroleum consultants, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter included as an exhibit to this Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has been practicing consulting petroleum engineering at NSAI since 2013 and has over 14 years of prior industry experience. NSAI has informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. Additionally, our senior management reviews any significant changes to our proved reserves on a quarterly basis. Our Director of Reservoir Engineering has over 30 years of oil and gas industry experience and has managed the preparation of public company reserve estimates the last 15 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, 2018 were estimated at $212.7 million.

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

	December 31,		
	2018	**2017**	**2016**
Proved undeveloped reserves, beginning of year	12.0	9.3	7.4
Transfers to proved developed reserves	(5.0)	(2.3)	(1.9)
Revisions of previous estimates	11.3	—	3.8
Extensions and discoveries	—	5.0	—
Purchase of minerals in place	2.2	—	—
Sales of minerals in place	(3.5)	—	—
Proved undeveloped reserves, end of year	17.0	12.0	9.3

The following table presents our estimates as to the timing of converting our PUDs to proved developed reserves (in MMBoe):

Year Scheduled for Development	**Number of PUD Locations**	**Percentage of PUD Reserves Scheduled to be Developed**
2019	4	41 %
2020	2	7 %
2021	4	32 %
2022	3	20 %
Total	13	100 %

Activity related to PUDs in 2018:

- Transfer of 5.0 MMBoe at three PUD locations from PUDs to proved developed reserves based on drilling such locations with total capital expenditures of $24.5 million during 2018.
- Net PUD additions of 11.3 MMBOE and eight net PUD locations primarily at our Ship Shoal 028 and our Mahogany fields.
- Conveyance of a portion of the working interest in properties which included 3.5 MMBoe of PUDs to the JV Drilling Program, 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 believe that we will be able to develop all but 1.8 MMBoe (approximately 11%) of the total 17.0 MMBoe classified as PUDs at December 31, 2018, within five years from the date such reserves were initially recorded. The lone exceptions are at the Matterhorn and 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 in each field, will be delayed until an existing well is depleted and available to sidetrack. Based on the latest reserve report, these PUD locations are expected to be developed in 2021 and 2022, respectively.

Acreage

The following table summarizes our leasehold at December 31, 2018. Deepwater refers to acreage in over 500 feet of water:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	410,101	230,828	105,131	85,613	515,232	316,441
Deepwater	159,209	57,459	46,080	20,544	205,289	78,003
Total	569,310	288,287	151,211	106,157	720,521	394,444

Approximately 73% 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, 18,802 net acres (18%) of the total 106,157 net undeveloped acres could expire in 2019; 1,152 net acres (1%) could expire in 2020; 5,760 net acres (5%) could expire in 2021; 7,835 net acres (7%) could expire in 2022; and 72,608 net acres (69%) could expire in 2023 and beyond. In making decisions regarding drilling and operations activity for 2019 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. For the leasehold that may expire in 2019, a substantial amount is on prospects that would not be economical to develop at current prices, the probability of successful drilling is estimated to be low or were acquired as part of an acquisition with no intent to develop.

Our net acreage increased 22,784 net acres (6%) from December 31, 2017 due to acquisitions and lease purchases, partially offset by sales, lease expirations and relinquishments.

Production

For the years 2018, 2017 and 2016, our net daily production averaged 36,510 Boe, 39,921 Boe and 41,980 Boe, respectively. Production decreased in 2018 from 2017 primarily due to natural production declines, pipeline and platform outages, and tropical storm activity, partially offset by production from six completed wells, which came on-line during various months throughout 2018, recompletion projects, workover projects and an acquisition consummated during 2018. 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.

Production History

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,		
	2018	2017	2016
Net Sales:			
Oil (MBbls)	6,687	7,064	7,201
NGLs (MBbls)	1,307	1,382	1,542
Oil and NGLs (MBbls)	7,994	8,446	8,743
Natural gas (MMcf)	31,991	36,754	39,731
Total oil equivalent (MBoe)	13,326	14,571	15,365
Total natural gas equivalents (MMcfe)	79,956	87,428	92,188

Volume measurements:
MBbls – thousand barrels for crude oil, condensate or NGLs
MBoe – thousand barrels of oil equivalent
MMcf – million cubic feet
MMcfe – million cubic feet equivalent

Refer to the descriptions of our 10 largest fields reported earlier in this Item 2,*Properties,* for historical information about our produced volumes from our Mahogany field and the Fairway Field over the past three fiscal years, which have proved reserves of 15% or more of our total proved reserves. Also refer to *Selected Financial Data – Historical Reserve and Operating Information* under Part II, Item 6 in this Form 10-K for additional historical operating data, including average realized sale prices and production costs.

Productive Wells

The following presents our ownership interest at December 31, 2018 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	76	50	37	135	113
Non-operated	37	9	29	8	66	17
Total offshore wells	122	85	79	45	201	130

(1) Includes seven gross (6.5 net) oil wells with multiple completions.

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

Drilling Activity

As presented in the tables below, our drilling activity increased in 2018 as compared to 2017. The table below is based on the SEC's criteria of completion or abandonment to determine productive 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,		
	2018	2017	2016
Development Wells Completed:			
Gross wells	3.0	3.0	—
Net wells	1.5	3.0	—
Exploration Wells Completed:			
Gross wells	3.0	1.0	1.0
Net wells	1.3	0.8	0.5

Our success rates related to our development and exploration wells drilled was 100% in 2018, 80% in 2017 and 100% in 2016. In 2017, we drilled one sub-sea well which had not been completed as of the filing date of this Form 10-K as we are evaluating various options on the well. As such, we have not reflected the well in the table above. One exploration well drilled during 2017 was non-commercial, of which we had a 39% working interest.

Recent Drilling Activity

During January 2018, we completed the A-17 offshore development well at Mahogany, which had been drilled to target depth during 2017 and began producing in March 2018. We also drilled and completed two other wells at Mahogany; the A-5 ST2 well which began producing in July 2018 and the A-19 well which began producing in November 2018. At Virgo, we drilled and completed two wells; the A-10 ST well, which began producing in April 2018 and the A-12 BP2 well which began producing in September 2018., The Virgo A-12 BP2 well is currently offline and we are evaluating methods by which to enhance production at that well. At South Timbalier 320, the A-2 well was drilled and completed during 2018 and began producing in December 2018.

During the first two months of 2019, we were in the process of completing the Virgo A-13 well and were drilling the South Timbalier 320 A-3 well.

The Mahogany A-5 ST well; the Virgo A-10 ST, A-12 BP2 and A-13 wells; and the South Timbalier 320 A-2 and A-3 wells are included in the JV Drilling Program.

Capital Expenditures

The level of our investment in oil and 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. We have set our 2019 capital expenditure budget at $120.0 million, which excludes potential acquisitions. 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 additional capital expenditure information.

Item 3. ***Legal Proceedings***

Apache Lawsuit. On December 15, 2014, Apache filed a lawsuit against the Company 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 $43.2 million, plus $6.3 million in prejudgment interest, attorney's fees and costs assessed in the judgment. We filed an appeal of the trial court judgment in the U.S. Court of Appeals for the Fifth Circuit and provided oral arguments in December 2018. Prior to filing the appeal, in order to stay execution of the judgment, we deposited $49.5 million with the registry of the court in June 2017. Oral arguments occurred on December 4, 2018, but as of the filing date of this Form 10-K, a decision had not been rendered by the U.S. Court of Appeals for the Fifth Circuit.

The deposit of $49.5 million with the registry of the U.S. Court of Appeals for the Fifth Circuit was recorded in *Other assets* (long-term) with a corresponding reduction to *Cash and cash equivalents* on the Consolidated Balance Sheet during 2017. Although we are appealing the decision, based solely on the decision rendered, we recorded $49.5 million in *Other liabilities* (long-term) and $43.2 million in capitalized ARO included in *Oil and natural gas properties and other, net* on the Consolidated Balance Sheet during 2017 and recognized $6.3 million of expense included in *Other (income) expense, net* on the Consolidated Statement of Operations in 2017.

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 the 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; 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 IBLA under the Department of the Interior. 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.

Royalties-In-Kind ("RIK"). Under a program of the Minerals Management Service ("MMS") (a Department of Interior 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. Based solely on the District Court's ruling, we recorded a liability reserve of $2.1 million as of December 31, 2018. We have appealed the ruling to the U.S. Fifth Circuit Court of Appeals, and the government filed a cross-appeal. Briefing and oral arguments (if held) will be completed in 2019.

Monetary Sanctions by Government Authorities (Notices of Proposed Civil Penalty Assessment). During 2018, we did not make any civil penalty payments and during 2017 and 2016, we paid $0.2 million and $0.1 million, respectively, in civil penalties to the BSEE related to Incidents of Noncompliance ("INCs") issued by the BSEE at various offshore locations. We currently have nine open civil penalties issued by the BSEE arising from INCs, which have not been settled as of the filing of this Form 10-K. The INCs underlying these open civil penalties cite alleged non-compliance with various safety-related requirements and procedures occurring at separate offshore locations on various dates ranging from July 2012 to January 2018. The proposed civil penalties for these INCs total $7.7 million. As of December 31, 2018, we have accrued approximately $3.5 million in expenses, which is our best estimate of the final settlement once all appeals have been exhausted. Our position is that the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

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	64	Chairman, Chief Executive Officer and President
Janet Yang	38	Executive Vice President and Chief Financial Officer
David M. Bump	52	Executive Vice President, Drilling, Completions and Facilities
William J. Williford	46	Executive Vice President and General Manager of Gulf of Mexico
Stephen L. Schroeder	56	Senior Vice President and Chief Technical Officer
Shahid A. Ghauri	50	Vice President, General Counsel and Corporate Secretary

(1) Ages as of February 23, 2019

Tracy W. Krohn has served as our Chief Executive Officer since he founded the Company in 1983, as President from 1983 until 2008 and again starting in March 2017, as Chairman of the Board since 2004 and as 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.

David M. Bump joined the Company in 2014 and was named Executive Vice President – Drilling, Completions and Facilities in November 2018. He previouslyserved as Vice President – Drilling and Completions since April 2014. Prior to joining the Company, Mr. Bump worked for Anadarko Petroleum Corporation (and predecessor Kerr-McGee) for 17 years in leadership positions overseeing both Gulf of Mexico and international offshore drilling and completion operations. Prior to 1997, he held various engineering positions at several small independent domestic operators.

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.

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*

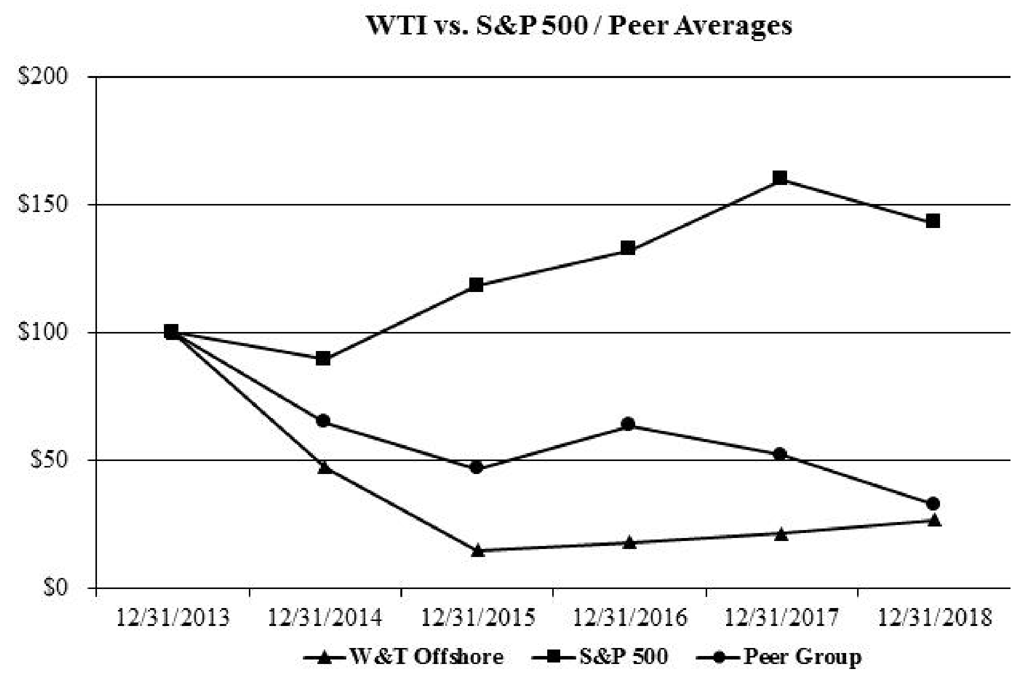
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of February 26, 2019, there were 177 registered holders of our common stock.

Dividends

During 2018 and 2017, no dividends were paid as dividend payments have been suspended. Dividends are subject to certain statutory requirements which include positive net equity. 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 is comprised of Apache Corporation, Bill Barrett Corp., Cabot Oil & Gas Corp., Comstock Resources, Inc., Newfield Exploration Co., and SM Energy Co. One of the companies in our 2017 peer group had been delisted and acquired by another company as of December 31, 2018 and was excluded from the 2018 peer group in the above graph.

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 2018, we did not purchase any of our equity securities.

The following table sets forth information about restricted stock units ("RSUs") delivered by employees during the quarter ended December 31, 2018 to satisfy tax withholding obligations on the vesting of RSUs:

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, 2018 – October 31, 2018	N/A	N/A	N/A	N/A
November 1, 2018 – November 30, 2018	N/A	N/A	N/A	N/A
December 1, 2018 – December 31, 2018	742,927	$ 4.84	N/A	N/A

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2018 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,				
	2018	2017	2016	2015	2014
	(In thousands, except per share data)				
Consolidated Statement of Operations Information:					
Revenues:					
Oil	$ 438,798	$ 340,010	$ 268,950	$ 349,191	$ 652,776
NGLs	37,127	32,257	26,429	27,665	72,837
Natural gas	99,629	108,923	100,405	123,435	217,816
Other	5,152	5,906	4,202	6,974	5,279
Total revenues	580,706	487,096	399,986	507,265	948,708
Operating costs and expenses:					
Lease operating expenses	153,262	143,738	152,399	192,765	264,751
Production taxes	1,832	1,740	1,889	3,002	7,932
Gathering and transportation	22,382	20,441	22,928	17,157	19,821
Depreciation, depletion and amortization	131,423	138,510	194,038	373,368	490,469
Asset retirement obligations accretion	18,431	17,172	17,571	20,703	20,633
Ceiling test write-down of oil and natural gas properties	—	—	279,063	987,238	—
General and administrative expenses	60,147	59,744	59,740	73,110	86,999
Derivative (gain) loss	(53,798)	(4,199)	2,926	(14,375)	(3,965)
Total costs and expenses	333,679	377,146	730,554	1,652,968	886,640
Operating income (loss)	247,027	109,950	(330,568)	(1,145,703)	62,068
Interest expense, net	48,645	45,521	84,382	97,205	78,194
Gain on debt transactions	47,109	7,811	123,923	—	—
Other (income) expense, net	(3,871)	5127	1,369	4,794	(6)
Income (loss) before income tax expense (benefit)	249,362	67,113	(292,396)	(1,247,702)	(16,120)
Income tax expense (benefit)	535	(12,569)	(43,376)	(202,984)	(4,459)
Net income (loss)	$ 248,827	$ 79,682	$ (249,020)	$ (1,044,718)	$ (11,661)
Basic and diluted earnings (loss) per common share	$ 1.72	$ 0.56	$ (2.60)	$ (13.76)	$ (0.16)
Dividends on common stock	—	—	—	—	30,260
Cash dividends per common share	—	—	—	—	0.40

SELECTED HISTORICAL FINANCIAL INFORMATION
(continued)

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In thousands)				
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 321,763	$ 159,408	$ 14,180	$ 133,228	$ 474,821
Net cash (used in) provided by investing activities	(66,385)	(107,107)	(82,396)	86,075	(592,502)
Net cash (used in) provided by financing activities	(321,143)	(23,479)	53,038	(157,555)	125,547

	December 31,				
	2018	2017	2016	2015	2014
	(In thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 33,293	$ 99,058	$ 70,236	$ 85,414	$ 23,666
Oil and natural gas properties and other, net (1)	515,421	579,016	547,053	990,049	2,493,857
Total assets (1)	848,866	907,580	829,726	1,208,022	2,689,508
Long-term debt (including current portion)	633,535	992,052	1,020,727	1,196,855	1,352,120
Shareholders' (deficit) equity (1)	(324,796)	(573,508)	(659,037)	(526,491)	509,308

(1) Ceiling test write-downs of $279.1 million and $987.2 million were recorded in 2016 and 2015, respectively.

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,				
	2018	2017	2016	2015	2014
Reserve Data: (1)					
Estimated net proved reserves					
Oil (MMBbls)	39.1	34.4	32.9	35.5	61.7
NGLs (MMBbls)	9.8	7.8	8.2	6.6	15.8
Natural Gas (Bcf)	210.5	192.2	197.8	205.4	254.9
Total barrel equivalents (MMBoe)	84.0	74.2	74.0	76.4	120.0
Total natural gas equivalents (Bcfe)	504.1	445.4	444.0	458.1	720.0
Proved developed producing (MMBoe)	53.9	54.5	47.3	57.6	68.7
Proved developed non-producing (MMBoe)	13.1	7.7	17.4	11.4	14.6
Total proved developed (MMBoe)	67.0	62.2	64.7	69.0	83.3
Proved undeveloped (MMBoe)	17.0	12.0	9.3	7.4	36.7
Proved developed reserves as %	79.8 %	83.8 %	87.4 %	90.3 %	69.4 %
Reserve additions (reductions) (MMBoe):					
Revisions (2)	21.1	9.6	13.0	(12.7)	4.1
Extensions and discoveries	2.1	5.2	—	4.1	9.7
Purchases of minerals in place	3.4	—	—	1.0	6.1
Sales of minerals in place (3)	(3.5)	—	—	(19.0)	—
Production	(13.3)	(14.6)	(15.4)	(17.0)	(17.6)
Net reserve additions (reductions)	9.8	0.2	(2.4)	(43.6)	2.3

(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 2015 also include revisions related to the Yellow Rose field up to the date of the sale.

(3) In 2018, sales of minerals in place primarily relate to conveyance of interest in properties to Monza. In 2015, sales of minerals in place primarily relate to the sale of the Yellow Rose field, excluding the overriding royalty interest.

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.

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

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Operating: (1)					
Net sales:					
Oil (MBbls)	6,687	7,064	7,201	7,751	7,176
NGLs (MBbls)	1,307	1,382	1,542	1,604	2,112
Oil and NGLs (MBbls)	7,994	8,446	8,743	9,355	9,288
Natural gas (MMcf)	31,991	36,754	39,731	46,163	50,088
Total oil equivalent (MBoe)	13,326	14,571	15,365	17,049	17,636
Total natural gas equivalents (MMcfe)	79,956	87,428	92,188	102,294	105,815
Average daily equivalent sales (Boe/day)	36,510	39,921	41,980	46,709	48,317
Average daily equivalent sales (Mcfe/day)	219,057	239,528	251,879	280,256	289,904
Average realized sales prices:					
Oil ($/Bbl)	$ 65.62	$ 48.13	$ 37.35	$ 45.05	$ 90.96
NGLs ($/Bbl)	28.40	23.35	17.14	17.25	34.49
Oil and NGLs ($/Bbl)	59.53	44.08	33.79	40.28	78.13
Natural gas ($/Mcf)	3.11	2.96	2.53	2.67	4.35
Oil equivalent ($/Boe)	43.19	33.02	25.76	29.34	53.49
Natural gas equivalent ($/Mcfe)	7.20	5.50	4.29	4.89	8.92
Average per Boe ($/Boe):					
Lease operating expenses	$ 11.50	$ 9.86	$ 9.92	$ 11.31	$ 15.01
Gathering and transportation	1.68	1.40	1.49	1.01	1.14
Production costs	13.18	11.26	11.41	12.32	16.15
Production taxes	0.14	0.12	0.12	0.17	0.42
DD&A (2)	11.24	10.68	13.77	23.11	28.98
General and administrative expenses	4.51	4.10	3.89	4.29	4.93
	$ 29.07	$ 26.16	$ 29.19	$ 39.89	$ 50.48
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 1.92	$ 1.64	$ 1.65	$ 1.88	$ 2.50
Gathering and transportation	0.28	0.23	0.25	0.17	0.19
Production costs	2.20	1.87	1.90	2.05	2.69
Production taxes	0.02	0.02	0.02	0.03	0.07
DD&A (2)	1.87	1.78	2.30	3.85	4.83
General and administrative expenses	0.75	0.68	0.65	0.71	0.82
	$ 4.84	$ 4.35	$ 4.87	$ 6.64	$ 8.41
Wells drilled (gross):					
Offshore	7	5	1	5	6
Onshore	—	—	—	5	33
Productive wells drilled (gross):					
Offshore	6	4	1	5	6
Onshore	—	—	—	5	33

(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

Volume measurements:

Bbl – barrel
MBoe – thousand barrels of oil equivalent
Mcfe – thousand cubic feet equivalent
MBbls – thousand barrels
Mcf – thousand cubic feet
MMcfe – million cubic feet equivalent
Boe – barrel of oil equivalent
MMcf – million cubic feet

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 *Financial Statements and Supplementary Data* under Part II, Item 8 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 with operations offshore in the Gulf of Mexico. We have grown through acquisitions, exploration and development, and currently hold working interests in 48 offshore fields in federal and state waters (47 producing and one field capable of producing). We currently have under lease approximately 720,000 gross acres (390,000 net acres) spanning across the Outer Continental Shelf ("OCS") off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 515,000 gross acres on the conventional shelf and approximately 205,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 123 offshore structures, 81 of which are located in fields that we operate. We currently own interest in 201 productive wells, 135 of which we operate. Our interest in fields, leases, structures and equipment are primarily owned by us directly and by our wholly-owned subsidiary, W & T Energy VI, LLC 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.

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 NGL's extracted from the natural gas). In addition, the prices of goods and services used in our business can vary and impact our cash flows and margins. During 2018, average commodity realized prices improved from those we experienced during 2017 and 2016. Our margins in 2018 have improved from 2017 and 2016 levels, and are approximately the margin levels achieved prior to 2015. We have historically increased our reserves and production through acquisitions, our drilling programs, and other projects that optimize production on existing wells. While our production decreased 8.5% in 2018 from the prior year, we added 23.1 MMBoe of proved reserves in 2018 replacing 174% of production. The 13.2% increase in proved reserves year-over-year is a result of successful drilling, technical revisions driven by improved well performance, recompletion and workover efforts, and improved commodity prices. During 2018, we completed one well which had reached target depth in 2017, and drilled and completed five additional wells which began producing during 2018. One of these wells, the Viosca Knoll 823 A-12 BP2, is currently offline and we are evaluating methods by which to enhance production at that well. Our plans for the short-term include operating within cash flow, maintaining liquidity, meeting our financial obligations and pursuing acquisitions meeting our criteria.

See *Properties – Proved Reserves* under Part I, Item 2; *Selected Financial Data* under Part II, Item 6 and *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 on our proved reserves.

Our drilling efforts in recent years have included the deepwater of the Gulf of Mexico. Production from our deepwater fields represented 41%, 42%, and 46% of our total production for the years 2018, 2017, and 2016, respectively. One of our larger deepwater fields is the Big Bend field, which commenced production in late 2015. Over 90% of our reserves in this field are composed of oil and NGLs on a Boe basis. As of December 31, 2018, the Big Bend field was in our top ten fields based on reserves, net to our interest, on a Boe basis.

To provide additional financial flexibility, we created the JV Drilling Program during 2018 and initiated drilling on several of the projects. The JV Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in 14 drilling projects. It also allows more projects to be taken on which leverages our capital expenditures and diversifies our risk. During 2018, there were four wells in the JV Drilling Program that came on production. In addition, as of December 31, 2018, one well was being drilled and one well was in the completion stage. The current plan is to complete the 14 projects within a three-year period, but is subject to change as needed with any required approval of the other investors. 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 JV Drilling Program.

In October 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, we issued $625.0 million of 9.75% Senior Second Lien Notes, which were issued at par with an interest rate of 9.75% per annum that matures on November 1, 2023. Concurrently, we renewed our credit facility by entering into the Credit Agreement, which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million. The borrowing base is subject to scheduled semi-annual redeterminations 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. Funds from the Senior Second Lien Notes, cash on hand and borrowings under the Credit Agreement were used to repurchase and retire, repay or redeem all of our previously outstanding secured senior notes and secured term loans. The Refinancing Transaction reduced our debt levels, extended the maturities for our fixed rate debt and provides extended liquidity under the Credit Agreement through October 2022. 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 of the transaction and the new debt instruments.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for 2018 were comprised of approximately 50% oil and condensate, 10% NGLs and 40% natural gas, determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs. The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices per Mcfe for crude oil, NGLs and natural gas may differ significantly. For 2018, our combined total production of oil, NGLs and natural gas was 8.5% below 2017, primarily due to natural production declines, partially offset by production from wells drilled and completed during 2018 and 2017 and from acquisitions.

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 2018, crude oil and NGL average realized prices were significantly above 2017 realized prices, increasing 36.3% and 21.6%, respectively.

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 January 2019 ("STEO"), worldwide production of petroleum and other liquids was estimated to have increased by 2.8% in 2018 over the prior year, which was higher than the year-over-year production growth experienced from the last two years of 0.5% for 2017 and 1.5% for 2016. The increases in production for 2018 were primary from increases in the U.S. Consumption for 2018 increased 1.5% over 2017 and was lower than production, resulting in inventory builds for 2018.

The EIA forecasts worldwide production of petroleum and other liquids year-over-year increases for 2019 and 2020 to be 1.4% and 1.7%, respectively. The increase is due primarily to increases in production in the U.S. and Brazil. For 2019, inventory builds are expected in the first half of 2019, putting downward pressure on prices and is forecasting markets to be relatively balanced in the second half of 2019. Consumption for 2019 and 2020 is estimated to increase by 1.5% on a year-over-year basis, with China, other Asian countries and the U.S. being the primary contributors to the increase in consumption.

According to EIA's STEO, U.S. crude oil production (excluding other petroleum liquids) increased 16.9% in 2018 over 2017, and is expected to increase year-over-year in 2019 and 2020 by 10.4% and 6.5%, respectively. For the U.S., net imports of crude oil in the U.S. fell by 14.5% in 2018 compared to 2017 and are expected to have another double-digit decline in 2019 from 2018. As noted below, the number of onshore rigs drilling for oil has increased from 2017 levels by approximately 18%.

Geopolitical events could greatly affect the prices for crude oil, natural gas and other petroleum products. While these events are difficult to predict, countries like Venezuela, Nigeria, Libya, and many Middle East countries have had, and could continue to have, disruptions due to political and economic factors outside of production issues. Venezuela's production in 2018 was at its lowest level since 2003 and their production is expected to continue to fall. Iran's production is down significantly from the beginning of 2018 compared to the end of 2018 as sanctions have been reinstated. 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 \$65.23 per barrel for 2018, up from \$50.80 barrel for 2017 (28.4% higher year-over-year). Brent crude oil prices averaged \$71.34 per barrel for 2018, up from \$54.12 per barrel for 2017 (31.8% higher year-over-year). Both WTI and Brent crude oil prices dropped in the fourth quarter 2018. From January 2, 2019 through February 15, 2019, average spot prices for WTI and Brent were below the average prices for the fourth quarter of 2018. The rising U.S. crude oil production puts upward price pressure on the Brent-to-WTI premium, which increased 82% to an average of \$6.12 per barrel for 2018 compared to an average of \$3.37 per barrel for 2017.

For 2018, our average realized crude oil sales price was \$65.62 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, 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 2018 improved on average by approximately \$2.00 per barrel compared to 2017 for these types of crude oils.

The EIA projects average crude oil prices for both WTI and Brent to decrease by approximately \$11.00 per barrel each for the year 2019 compared to 2018 as supply is forecasted to be greater than consumption. EIA's forecast of crude oil prices for WTI and Brent for 2020 is an increase above 2019 levels of approximately \$5.00 per barrel each.

During 2018, our average realized NGLs sales price per barrel increased by 21.6% compared to 2017. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During 2018, average prices for domestic ethane increased by 24% and average domestic propane prices increased by 14% from 2017 as measured using a price index for Mount Belvieu. The average price for other domestic NGLs components ranged from an increase of 9% to 24% for 2018 year-over-year. We believe the increase in prices for NGLs is mostly a function of the change in crude oil prices and propane usage during the recent winter season. Per EIA, production of ethane is expected to increase by 15% in 2019 compared to 2018 and increase by 9% in 2020 compared to 2019. Propane production is expected to increase by 13% in 2019 compared to 2018 and by 4% in 2020 compared to 2019. Ethane inventories decreased 7% as of December 2018 compared to December 2017. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Additional ethane steam crackers coming on line is impacting the usage of ethane, which is believed to positively impact the price. 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. Propane inventory levels are 3% higher at the end of 2018 compared to the end of 2017. Heating degree days were 16% higher in the first half of 2018 compared to the same period last year.

During 2018, our average realized natural gas sales price increased 5.1% compared to 2017. According to data from EIA's web site, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 5.2% higher in 2018 compared to 2017. 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 2018 were 11% lower than year end 2017 and were 18% below the five-year average for the previous five years.

EIA projects natural gas supply to be greater than consumption in 2019 and forecast prices to drop by 8% to approximately \$3.00 per Mcf. We believe several factors are causing the continued weakness including (i) producers continuing to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas continuing to be produced as a by-product of oil drilling, (iii) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling, pad drilling and production techniques and (iv) re-injecting ethane from time to time into the natural gas stream, which increases the natural gas supply.

EIA's reports that electrical power generation sourced by natural gas consumption increased from 32% in 2017 to 35% in 2018 and forecast this percentage to increase to 36% in 2019 and 37% in 2020. The percentage of electrical power generation sourced from coal fell in 2018 and is expected to decrease further in 2019 and 2020. The percentage of electrical power sourced from renewable sources such as hydropower and wind remained constant in 2018 as compared to 2017 at 17%, but is forecast to increase during 2019 and 2020 to 18% and 20%, respectively.

As of December 31, 2018, the number of working rigs drilling for oil and natural gas in the U.S. was higher than year ago levels for land based rigs (increase of 147 rigs, or 16%), and higher in offshore waters (increase of six rigs or 33%). According to Baker Hughes, the oil rig count at the end of December 2018 and December 2017 was 885 and 747, respectively. The U.S. natural gas rig count at the end of December 2018 and December 2017 was 198 and 182, respectively. In the Gulf of Mexico, the number of working rigs was 24 rigs (20 oil and four natural gas rigs) at the end of December 2018 and 18 rigs (14 oil and four natural gas) at the end of December 2017.

As of December 31, 2018, we had $33.3 million of available cash and $219.4 million available under our Credit Agreement, which currently has a borrowing base of $250.0 million. See the *Liquidity and Capital Resources* section of this Item 7, and *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for a description of our debt structure.

For 2018, cash used for investing activities related to oil and gas properties and equipment was $106.2 million, which was the same amount of cash used for similar investments in 2017. For 2016, cash used for investing activities related to oil and gas properties and equipment was $83.8 million, which were reduced primary due to the low realized crude oil prices and volatility in the markets. The levels for the last three years are below the cash used for investing activities related to oil and gas properties and equipment in 2015 and 2014, which were $285.6 million and $516.9 million, respectively. These amounts exclude acquisitions made in 2018 and 2014 and there were no material acquisitions in 2017, 2016 or 2015. For 2019, we have set our initial capital expenditure budget at $120.0 million which excludes acquisitions. The budget incorporates our capital spending relating to the JV Drilling Program (net to our interest). We strive to maintain flexibility in our capital expenditure projects and if prices remain at current levels or 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 2018 impacted our production for 2018, but most of the impact is expected to occur in 2019 and beyond. In addition, we spent $28.6 million in 2018 and $72.4 million in 2017 for ARO and plan to spend $25.0 million in 2019 for ARO.

Our operating costs in 2018 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. During 2018, our lease operating expenses increased 6.6% compared to 2017 on an absolute basis. The increase was primarily due to incurring operating costs associated with an acquisition consummated during 2018 and lower product handling arrangement ("PHA") fees in 2018 for certain fields as compared to 2017, which are recorded as credits to expense, insurance premiums and workover expenses. 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.

In recent years, we have operated or participated in wells near the outer edge of the continental shelf and in the deepwater of the Gulf of Mexico. To the extent we continue expanding our deepwater operations, our operating and ARO costs may increase, especially as we find and produce more crude oil rather than natural gas.

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

Applicable environmental regulations require us to remove our platforms after production has ceased, to plug and abandon all wells and to remediate environmental damage our operations may have caused. These types of activities are collectively referred to as decommissioning or ARO. The costs per well associated with our ARO generally increase as we drill wells in deeper parts of the continental shelf and in the deepwater. We generally do not pre-fund our ARO, but have obtained approximately $270.0 million in bonds related to ARO. Over the last ten years, we have spent over $690.0 million for ARO. We estimated the present value of our liability related to our ARO at $310.1 million as of December 31, 2018, of which $25.0 million is estimated to be spent during 2019. Inherent in the present value calculation of our liability are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and expenditure, and changes in the legal, regulatory, environmental and political environments. Actual expenditures for ARO could vary significantly from these estimates and have varied significantly in the past. Prior to 2015, we saw upward revisions in costs to do this work partly due to significant changes in the regulatory requirements and partly due to the escalation in the cost of goods and services required to do the work. The increase in oil prices that occurred over several years before the decline that began in June 2014 led to significant cost inflation of goods and services in the Gulf of Mexico and other producing basins.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. The process for obtaining offshore drilling permits, especially deepwater drilling permits, has expanded and lengthened in the past few years. Significant regulatory changes in recent years include NTL #2016-N01 and interpretations related to unbundling costs at natural gas plants, which adversely impact royalty payments. In addition, regulations have expanded related to potential environmental impacts, spill response documentation, compliance reviews and operator practices related to safety and environmental matters. This has led to higher costs for revisions, training, implementations and monitoring related to our safety and environmental management systems. The new regulations and increased review process increases the time to obtain drilling permits and increases the cost of operations. Also, the regulations have changed related to decommissioning, including plugging and abandonment of offshore wells and related infrastructure considerably, driving up both the time and cost to perform the work. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time. See *Business - Regulation* under Part I, Item 1 in this Form 10-K for additional information.

Our current focus is on making profitable investments with short payback time frames while operating within cash flow, maintaining sufficient liquidity, cost reductions and fulfilling our obligations. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans. See Item 1A, Risk Factors, in this Form 10-K for additional information.

Results of Operations

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Revenues. Total revenues increased $93.6 million, or 19.2%, to $580.7 million in 2018 as compared to $487.1 million in 2017. Oil revenues increased $98.8 million, or 29.1%, NGLs revenues increased $4.9 million, or 15.1%, natural gas revenues decreased $9.3 million, or 8.5%, and other revenues decreased $0.8 million. The oil revenue increase was attributable to a 36.3% per barrel increase in the average realized sales price to $65.62 per barrel in 2018 from $48.13 per barrel in 2017, partially offset by a 5.3% decrease in sales volumes. The NGLs revenue increase was attributable to a 21.6% increase in the average realized sales price to $28.40 per barrel in 2018 from $23.35 per barrel in 2017, partially offset by a decrease of 5.4% in sales volumes. The decrease in natural gas revenue was attributable to a 13.0% decrease in sales volumes, partially offset by a 5.1% increase in the average realized natural gas sales price to $3.11 per Mcf in 2018 from $2.96 per Mcf in 2017. Overall, prices increased 30.8 % on a per Boe basis and production declined 8.5% on a per Boe per day basis. The largest production increases for 2018 compared to 2017 were from our newly acquired interest in the Heidelberg field and our Ship Shoal 300 field. Revenue and production was adjusted for royalty relief on two of our deepwater fields related to their 2017 and 2016 production and realized prices which is recognized in the subsequent year. This royalty relief impact to revenues during 2018 and 2017 was $1.0 million and $5.0 million, respectively. Offsetting were production decreases primarily due to natural production declines and production deferrals. Production for 2018 was also negatively impacted by maintenance, well issues and pipeline outages that collectively resulted in deferred production of 1.6 MMBoe, which was approximately the same amount as in 2017.

Revenues from oil and liquids as a percent of our total revenues were 82.0% for 2018 compared to 76.4% for 2017. NGLs realized sales prices as a percent of crude oil realized prices decreased to 43.3% for 2018 compared to 48.5% for 2017.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, increased $9.5 million, or 6.6%, to $153.3 million in 2018 compared to $143.7 million in 2017. The Heidelberg field acquisition accounted for approximately half of the lease operating expense increase. On a per Boe basis, lease operating expenses increased to $11.50 per Boe during 2018 compared to $9.86 per Boe during 2017. On a component basis, base lease operating expenses increased $5.1 million and insurance premiums increased $2.2 million and workover expenses increased $2.3 million, partially offset by facilities maintenance decreases of $0.1 million. Base lease operating expenses increased primarily due the addition of the Heidelberg field, lower product handling and operating charges to an outside party at our Matterhorn field and higher incentive compensation expenses. The insurance premium increase is primarily due to our insurance policies related to named windstorms, which had expanded coverage in 2018 compared to the 2017 period, as named windstorm coverage was limited to just our Mahogany field in the first half of 2017. The increase in workover expenses is primarily attributable to additional projects at our Mahogany field compared to the prior year to increase production.

Production taxes. Production taxes were $1.8 million, approximately the same as in 2017. Most of our production is from federal waters where no production taxes are imposed. Our Fairway field, which is in state waters, is subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased to $22.4 million, or 9.5%, in 2018 compared to $20.4 million in 2017 primarily related to the Heidelberg field, where we are required to pay additional amounts if throughputs are below minimums quantities and were partially offset by lower expenses from lower production volumes.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, increased to $11.24 per Boe in 2018 from $10.68 per Boe in 2017. On a nominal basis, DD&A decreased to $149.9 million (3.7%) in 2018 from $155.7 million in 2017. DD&A on a nominal basis decreased primarily due to lower production, partially offset by an increase in the DD&A rate. Factors affecting the DD&A rate are capital expenditures, changes in future development costs on remaining reserves and changes in proved reserve volumes.

General and administrative expenses ("G&A"). For 2018, G&A expenses of $60.1 million were essentially at the same level as in 2017. We experienced reductions in legal settlements, fines and contract labor, offset by increases for settlements related to the departure of certain executives, increases in medical claims and a buyout of an office lease. G&A on a per BOE basis was $4.51 Boe for 2018 compared to $4.10 Boe for 2017. 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 for additional information

Derivative gain. For 2018, a $53.8 million derivative gain was recorded for crude oil and natural gas derivative contracts. We entered into derivative contracts for crude oil during the second quarter of 2018 relating to a portion of our 2018 estimated production, which expired in December 2018. In the fourth quarter of 2018, we entered into additional derivative contracts for crude oil and natural gas, which consists primarily of crude oil contracts with a term of 18 months. For 2017, a $4.2 million derivative gain was recorded for crude oil and natural gas derivative contracts. We entered into derivative contracts for crude oil and natural gas during the first quarter of 2017 relating to a portion of our 2017 estimated production and there were no open contracts as of December 31, 2017. 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 $48.6 million in 2018, increasing 6.9% from $45.5 million in 2017. The increase was primarily attributable to the Refinancing Transaction that was completed in October 2018. Prior to the Refinancing Transaction, a portion of our interest was recorded as offsets to carrying value adjustments on the balance sheet under Accounting Standard Codification Topic 470-60, *Troubled Debt Restructuring* ("ASC 470-60"), which lowered reported interest expense during 2017 and from January 1, 2018 to October 18, 2018. After the Refinancing Transaction, all of our interest cost is reported as interest expense. Partially offsetting was an increase in interest income to $2.4 million to 2018 compared to $0.3 million in 2017. *See Financial Statements and Supplementary Data - Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information.

Gain on exchange of debt. During 2018, the Refinancing Transaction resulted in a gain of $47.1 million for 2018. During 2017, a net gain of $7.8 million was recognized primarily as a result of paying interest in cash on certain debt instruments that had the option of paying-in-kind (“PIK”) or in cash. *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 2018 and 2017, other (income) expense, net, was $3.9 million of net income and $5.1 million of net expense, respectively. For 2018, the amount consists of credits related to the de-recognition of certain liabilities that had exceeded the statute of limitations, partially offset by expenses related to the amortization of the brokerage fee paid in connection with the JV Drilling Program. For 2017, the amount consists primarily of expense items related to the Apache lawsuit of $6.3 million, partially offset by loss-of-use reimbursements from a third-party for damages incurred at one of our platforms of $1.1 million. *See Financial Statements and Supplementary Data - Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information.

Income tax benefit. Our income tax expense for 2018 was $0.5 million and our income tax benefit for 2017 was $12.6 million. For 2018, immaterial deferred tax expense was recorded due to dollar-for-dollar offsets by our valuation allowance. The income tax benefit for 2017 was primarily attributable to claims made pursuant to Internal Revenue Code (“IRC”) Section 172(f), (related to rules for “specified liability losses”) which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. Our annual effective tax rate for 2018 and 2017 was not meaningful and differs from the federal statutory rates of 21% and 35%, respectively, primarily due to the valuation allowances recorded for our deferred tax assets in both periods. During 2018, we recorded a decrease to the valuation allowance of $53.8 million related to federal and state deferred tax assets. A corresponding change for substantially an equivalent amount occurred in our deferred tax assets for 2018. 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.

On December 22, 2017, the TCJA was enacted into law and we applied the guidance in Staff Accounting Bulletin No. 118 (“SAB 118”) when accounting for the enactment-date effects of the TCJA throughout 2018. At December 31, 2017, we had not completed our accounting for all of the enactment-date income tax effects of the TCJA under Accounting Standards Codification Topic 740, *Income Taxes*, (“ASC 740”) for the measurement of deferred tax assets and liabilities. As of December 31, 2018, we have completed our accounting for all of the enactment-date income tax effects of the TCJA. During 2018, we recognized an adjustment to $0.5 million to the provisional amounts recorded at December 31, 2017.

For 2019, we do not expect to make any significant income tax payments. See *Financial Statements and Supplementary Data – Note 13 – Income Taxes* under Part II, Item 8 in this Form 10-K for additional information.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Revenues. Total revenues increased $87.1 million, or 21.8%, to $487.1 million in 2017 as compared to $400.0 million in 2016. Oil revenues increased $71.1 million, or 26.4%, NGLs revenues increased $5.8 million, or 22.1%, natural gas revenues increased $8.5 million, or 8.5%, and other revenues increased $1.7 million. The oil revenue increase was attributable to a 28.9% per barrel increase in the average realized sales price to $48.13 per barrel in 2017 from $37.35 per barrel in 2016, partially offset by a 1.9% decrease in sales volumes. The NGLs revenue increase was attributable to a 36.2% increase in the average realized sales price to $23.35 per barrel in 2017 from $17.14 per barrel in 2016, partially offset by a decrease of 10.4% in sales volumes. The increase in natural gas revenue was attributable to a 17.0% increase in the average realized natural gas sales price to $2.96 per Mcf in 2017 from $2.53 per Mcf in 2016, partially offset by a 7.5% decrease in sales volumes. Overall, prices increased 28.2 % on a per Boe basis and production declined 4.9% on a per Boe per day basis. The largest production increases for 2017 compared to 2016 were at the Mahogany, Ewing Bank 910, Virgo and East Cameron 321 fields. In addition, we received royalty relief in 2017 for a portion of 2016 crude oil royalties and all 2016 natural gas royalties related to the Mississippi Canyon 698 ("Big Bend") and Mississippi Canyon 782 ("Dantzler") fields, which increased revenues by $5.0 million and sales volumes by approximately 175,000 MBoe. Offsetting were production decreases primarily due to natural production declines and production deferrals. Production deferrals from hurricanes, pipeline outages and other events were estimated at 1.7 MMBoe, approximately the same amount as in 2016.

Revenues from oil and liquids as a percent of our total revenues were 76.4% for 2017 compared to 73.8% for 2016. NGLs realized sales prices as a percent of crude oil realized prices increased to 48.5% for 2017 compared to 45.9% for 2016.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $8.7 million, or 5.7%, to $143.7 million in 2017 compared to $152.4 million in 2016. On a per Boe basis, lease operating expenses decreased to $9.86 per Boe during 2017 compared to $9.92 per Boe during 2016. On a component basis, base lease operating expenses decreased $10.5 million and insurance premiums decreased $2.4 million, partially offset by facilities maintenance increases of $2.5 million, insurance reimbursements of $1.2 million in the 2016 period only and workover expense increases of $0.5 million. Base lease operating expenses decreased primarily due to lower costs from service providers resulting primarily from lower levels of activity in the Gulf of Mexico, higher PHA fees (cost offsets) at certain fields and lower charges from non-operated properties. Insurance premium reductions are primarily due to reduction in the Energy Package related to named windstorms coverage. The increase in facilities maintenance expenses was primarily due to engine and compressor overhauls. For insurance reimbursements, we received reimbursements in 2016, of which a component was for lease operating expenses. No such insurance reimbursements were received during 2017. The increase in workover costs was primarily due to well work at the Mahogany field.

Production taxes. Production taxes decreased $0.1 million in 2017 compared to 2016. Most of our production is from federal waters where no production taxes are imposed. Our Fairway field, which is in state waters, is subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased to $20.4 million, or 10.8%, in 2017 compared to $22.9 million in 2016 primarily due to due to lower production volumes of NGLs and natural gas.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $10.68 per Boe in 2017 from $13.77 per Boe in 2016. On a nominal basis, DD&A decreased to $155.7 million (26.4%) in 2017 from $211.6 million in 2016. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2016 and lower capital expenditures in relation to DD&A expense during 2016, both of which lowers the full-cost pool subject to DD&A. Other factors affecting the DD&A rate are changes in future development costs on remaining reserves and changes in proved reserve volumes.

Ceiling test write-down of oil and natural gas properties. For 2017, no ceiling test write-downs were recorded. For 2016, we recorded non-cash ceiling test write-downs of $279.1 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is the result of decreases in prices during 2016 for all three commodities we sell, which are crude oil, NGLs and natural gas. See *Financial Statements and Supplementary Data – Note 1 - Basis of Presentation* under Part II, Item 8 in this Form 10-K, which provides a description of the ceiling test limit determination.

General and administrative expenses. For 2017, G&A expenses of $59.7 million were essentially at the same level as in 2016. We experienced reductions in salary expense, legal expense, benefits costs and information technology costs, offset by increases in incentive compensation, accrued civil penalties from the BSEE (which we are appealing to the IBLA) and surety bond costs. G&A on a per BOE basis was $4.10 Boe for 2017 compared to $3.89 Boe for 2016. 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 for additional information

Derivative (gain) loss. For 2017, a $4.2 million derivative gain was recorded for crude oil and natural gas derivative contracts. We entered into derivative contracts for crude oil and natural gas during the first quarter of 2017 relating to a portion of our 2017 estimated production and there were no open contracts as of December 31, 2017. For 2016, a $2.9 million derivative loss was recorded for our crude oil and natural gas derivative contracts. 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 $45.5 million in 2017, decreasing 46.1% from $84.4 million in 2016. The decrease was primarily attributable to the transaction that was completed on September 7, 2016, when we exchanged $710.2 million of our Unsecured Senior Notes for $301.8 million of new secured notes and 60.4 million shares of common stock, and at the same time, closed on a $75.0 million, 1.5 Lien Term Loan (the "Exchange Transaction"). In addition, interest expense was lower as we had no borrowings on the revolving bank credit facility during 2017 compared to borrowings averaging approximately $150.0 million during the period from January 1, 2016 to the close of the Exchange Transaction on September 7, 2016. *See Financial Statements and Supplementary Data - Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information.

Gain on exchange of debt. During 2017, a net gain of $7.8 million was recognized primarily as a result of paying interest in cash on certain debt instruments with the option of paying-in-kind PIK or in cash. The cash interest payments lowered the carrying value of the respective notes under ASC 470-60, resulting in the recognition of a non-cash gain. The cash payments had a lower interest rate compared to the PIK option and this also reduced future interest and principal payments. Partially offsetting were additional expenses related to the Exchange Transaction for differences between estimated and actual expense. During 2016, a net gain of $123.9 million was recognized related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as undiscounted future cash flows of the debt issued in the Exchange Transaction, plus the fair value of the common stock issued and deal transaction costs were less than the sum of the carrying value of the Unsecured Senior Notes exchanged combined with the funds received from the 1.5 Lien Term Loan issued. *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 2017 and 2016, other (income) expense, net, was $5.1 million of net expense and $1.4 million of net expense, respectively. For 2017, the amount consists primarily of expense items related to the Apache lawsuit of $6.3 million, partially offset by loss-of-use reimbursements from a third-party for damages incurred at one of our platforms of $1.1 million. For 2016, write-downs of unamortized debt issuance costs were recorded related to a reduction in the borrowing base on the revolving bank credit facility. The reductions in the borrowing base resulted in proportional reductions in 2016 of $1.4 million in the unamortized debt issuance costs related to the revolving bank credit facility. *See Financial Statements and Supplementary Data - Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information.

Income tax benefit. Our income tax benefit for 2017 and 2016 was $12.6 million and $43.4 million, respectively. The income tax benefit for both years was primarily attributable to claims made pursuant to IRC Section 172(f), (related to rules for "specified liability losses") which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. Our annual effective tax rate for 2017 and 2016 was not meaningful and differs from the federal statutory rate of 35% primarily due to the valuation allowances recorded for our deferred tax assets in both periods. During 2017, we recorded a decrease to the valuation allowance of $118.6 million, and during 2016, we recorded increases to the valuation allowance of $52.9 million related to federal and state deferred tax assets. A corresponding change for substantially an equivalent amount occurred in our deferred tax assets for both years. 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.

On December 22, 2017, the TCJA was enacted into law and we applied the guidance in SAB 118 when accounting for the enactment-date effects of the TCJA in 2017. This new law impacted certain components of our 2017 financial statements by requiring us to provisionally re-measure our net deferred tax assets at year-end 2017 downwards by $105.9 million. A corresponding reduction in our valuation allowance for substantially an equivalent amount was also recorded at year-end 2017. At December 31, 2017, we had not completed our accounting for all of the enactment-date income tax effects of the TCJA under ASC 740 for the measurement of deferred tax assets and liabilities. Our tax benefit recorded on the Consolidated Statement of Income for the year 2017 was not materially impacted as a result of the provisional re-measurement of our net deferred tax assets and its related valuation allowance. Our Consolidated Balance Sheet as of December 31, 2017 and our Consolidated Statement of Cash Flows for the year 2017 were also not impacted as a result of the enactment of the TCJA. See *Financial Statements and Supplementary Data – Note 13 – Income Taxes* under Part II, Item 8 in this Form 10-K for additional information.

Liquidity and Capital Resources

Our primary liquidity needs are to 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.

If commodity prices were to return to the weaker levels seen in the early part of 2016, especially relative to our cost of finding and producing new reserves, this could have a significant adverse effect on our liquidity. In addition, other events outside of our control could significantly affect our liquidity such as demands for additional financial assurances from the BOEM.

Additionally, a prolonged period of weak commodity prices could have other potential negative impacts including:

- recognizing additional 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.

Joint Venture Drilling Program. To provide additional financial flexibility, we created the JV Drilling Program during 2018 and initiated drilling on several of the projects. The JV Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in 14 projects that we believe have great potential. It also allows more projects to be taken on which leverages our capital expenditures and diversifies our risk. During 2018, there were four wells in the JV Drilling Program that came on production. In addition, as of December 31, 2018, one well was being drilled and one well was in the completion stage. The current plan is to complete the 14 projects within a three-year period, but is subject to change as needed with any required approval of the other investors.

Refinancing Transaction. In October 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, we issued $625.0 million of 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. Concurrently, we renewed our credit facility by entering into the Credit Agreement, which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million. The borrowing base is subject to scheduled semi-annual redeterminations 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. Funds from the Senior Second Lien Notes, cash on hand and borrowings under the Credit Agreement were used to repurchase and retire, repay or redeem all of our previously outstanding secured senior notes and secured term loans. The Refinancing Transaction reduced our debt levels, extended the maturities for our fixed rate debt and provides extended liquidity under the Credit Agreement through October 2022. 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 of the transaction and the new debt instruments.

Credit Agreement. As of December 31, 2018, we had $21.0 million borrowings outstanding under the Credit Agreement and $9.6 million of letters of credit issued under the Credit Agreement. During 2018, borrowings under the Credit Agreement and Prior Credit Agreement ranged from zero million to $61.0 million. Availability under our Credit Agreement as of December 31, 2018 was $219.4 million.

Availability under our Credit Agreement is subject to a semi-annual redetermination of our borrowing base as discussed above. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our Credit Agreement. The Credit Agreement is secured and is collateralized by substantially all of our oil and natural gas properties.

We currently have six lenders within the revolving bank credit facility, with commitments ranging from $25.0 million to $62.5 million for 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, 2018.

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.

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.

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.

Cash Flows. Net cash provided by operating activities for 2018 was $321.8 million, more than double the $159.4 million for 2017. The change between periods is primarily due to higher realized prices for crude oil and NGLs, lower spending for ARO activities and working capital changes. Our combined average realized sales price per Boe increased 30.8% in 2018, which caused total revenues to increase $128.4 million, partially offset by decreases of 8.5% in production volumes which caused revenues to decrease by $34.0 million.

Other items affecting operating cash flows for 2018 were ARO settlements of $28.6 million, which decreased from $72.4 million in 2017 and cash advances from joint venture partners increased $16.6 million. During 2018, derivative payments, net, were $20.8 million primarily due to premiums paid for derivative call-option oil contracts compared to derivative cash receipts, net, for 2017 of $4.2 million. During 2017, we received insurance reimbursements of $31.7 million and made a deposit related to the Apache matter of $49.5 million. Working capital items accounted for the balance of the change in net cash provided by operating activities.

Net cash used in investing activities during 2018 and 2017 was $66.4 million and $107.1million, respectively, which represents our investments in oil and gas properties and equipment. Investments in oil and natural gas properties 2018 were $106.2 million, which was the same amount of investments as in 2017. The majority of our capital expenditures for 2018 related to investments on the conventional shelf in the Gulf of Mexico and, to a lesser extent, in the deep waters of the Gulf of Mexico. The net purchase price for the acquisition of the Heidelberg field was $16.8 million, which was acquired during 2018 and there were no material acquisitions in the prior year period. The sale of our overriding royalty interests in the Permian Basis fields resulted in net proceeds of $56.6 million and there were no asset sales of significance in the prior year period.

Net cash used by financing activities for 2018 and 2017 was $321.1 million and $23.5 million, respectively. The net cash used for 2018 was primarily related to the Refinancing Transaction which included issuance of the Senior Second Lien Notes and extinguishment of all the prior debt instruments. In addition, cash used during 2018 included interest payments on the 11.00% 1.5 Lien Term Loan, the 9.00%/10.75% Senior Second Lien PIK Toggle Notes and the 8.50%/10.00% Senior Third Lien PIK Toggle Notes (collectively, the "2016 Debt"), which are reported as financing activities under ASC 470-60. The net cash used for 2017 was primarily attributable to the interest payments on the 2016 Debt.

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 2018 and 2017, 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, 2018, we had outstanding open derivatives for crude oil and natural gas, of which the majority are oil contracts which expire in May 2020. See *Financial Statements and Supplementary Data - Note 9 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Hurricane remediation, insurance claims and insurance coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which $203.1 million has been collected through December 31, 2018, which includes $31.7 million collected during 2017. As of December 31, 2018 and 2017, there were no claims outstanding related to any hurricanes.

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 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 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, 2018. 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, 2018 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 Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE and we have insurance coverage of such amount.

Although we were able to renew our general and excess liability policies effective on May 1, 2018, and our Energy Package effective on June 1, 2018, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. 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 insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

The premiums for the above policies including brokerage fees were $11.8 million for the May/June 2018 policy renewals compared to $10.9 million for the expiring policies. The increase in our premiums effective with the May/June 2018 renewal was primarily attributable to expanding the number of properties covered and the type of coverage for named windstorm damage.

Capital expenditures. The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors including the prices of crude oil, NGLs and natural gas; acquisition opportunities; liquidity and financing options; and the results of our exploration and development activities. The following table presents our investments in oil and gas properties and equipment for exploration, development, acquisitions and other leasehold costs:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Exploration [1]	$ 49,890	$ 57,088	$ 1,541
Development [1]	47,224	71,054	45,183
Acquisition of interest – Heidelberg Field [2]	16,782	—	—
Reimbursement from Monza for 2017 expenditures	(14,075)	—	—
Seismic, capitalized interest, other	7,702	1,906	1,882
Acquisitions and investments in oil and gas property/equipment	$ 107,523	$ 130,048	$ 48,606

(1) Reported geographically in the subsequent table.

(2) Acquired 9.375% non-operated working interest in April 2018.

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

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Conventional shelf	$ 69,354	$ 121,922	$ 38,631
Deepwater	27,760	6,220	8,093
Exploration and development capital expenditures	$ 97,114	$ 128,142	$ 46,724

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		
	2018	2017	2016
Offshore – gross wells drilled:			
Conventional shelf	3	4	—
Deepwater	3	—	1
Wells operated by W&T	5	4	—

We had a 100% success rate in 2018, 80% success rate in 2017 and 100% in 2016. One of the deepwater wells completed in 2018, the Virgo A-12 BP2 well, is currently offline and we are evaluating methods by which to enhance production at that well. In 2017, we drilled one sub-sea well which had not been completed as of the filing date of this Form 10-K as we are evaluating various options on the well. As such, we have not reflected the well in the table above. We drilled one exploration well on the conventional shelf during 2017 that was non-commercial, of which we had a 39% working interest.

During the first two months of 2019, we were in the process of completing the Virgo A-13 well and were drilling the South Timbalier 320 A-3 well.

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.

Over the last three years, we have acquired 19 leases for approximately $2.1 million from the BOEM in the Federal Offshore Lease Sale. Per year, we acquired 17 leases ($1.9 million), one lease ($0.1 million) and one lease ($0.1 million) in the years 2018, 2017 and 2016, respectively.

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 2017 and 2016, 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.

Liquidity assessment for 2019. Our assessment of our liquidity needs for 2019 is that we will have adequate liquidity from cash flow from operations to fund our capital expenditure plans for 2019, fund our ARO spending for 2019 and fulfill our various other obligations. Availability under our Credit Agreement as of December 31, 2018 was $219.4 million. In addition, we have derivative contracts that extend to May 2020 that cover a portion of our expected production and we expect to receive a tax refund of $54.1 million during 2019 as discussed below. Our initial capital expenditure budget for 2019 is $120.0 million, which excludes potential acquisitions, with over 70% allocated to development. In our view of the outlook for 2019, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2019 and beyond. If our liquidity would become 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, 2018, we have current income taxes receivable of $54.1 million. The income taxes receivable relates primarily to our NOL claims for the years 2012, 2013 and 2014 that were carried back to prior years and require a review from the Congressional Joint Committee on Taxation prior to payments being made. The receivable relates to claims made pursuant to IRC rules for specified liability losses, which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. Under the TCJA effective in 2018, the rules related to specified liability losses have been eliminated and additional carryback claims were not allowed in 2018 and will not be allowed going forward. The TCJA does not affect claims previously filed, noted above, nor does the TCJA affect the review process for such claims. For 2019, we do not expect to make any significant income tax payments.

Dividends. During 2018, 2017 and 2016, we did not pay any dividends and a suspension of dividends remains in effect.

Asset retirement obligations. Each year (and often more frequently) we review and revise our ARO estimates. Our ARO at December 31, 2018 and 2017 were $310.1 million and $300.4 million, respectively, recorded using discounted values. Our estimate of ARO spending in 2019 is $25.0 million. During 2018 and 2017, we revised our estimates of costs anticipated to be charged by service providers for plugging and abandonment projects. 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 new and 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.

Contractual obligations. At December 31, 2018, we did not have any capital leases. The following table summarizes our significant contractual obligations by maturity as of December 31, 2018:

	Payments Due by Period as of December 31, 2018				
	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt – principal	$ 646.0	$ —	$ —	$ 646.0	$ —
Long-term debt – interest (1)	315.0	65.2	126.2	123.6	—
Drilling rigs	9.7	9.7	—	—	—
Operating leases	6.3	1.5	3.2	1.6	—
Asset retirement obligations (2)	310.1	25.0	31.1	61.8	192.2
Other liabilities and commitments (3)	70.9	10.3	14.4	10.6	35.6
Total	$ 1,358.0	$ 111.7	$ 174.9	$ 843.6	$ 227.8

(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, 2018 and assumes no change in this interest rate in future periods. In addition, a commitment fee of 0.375% was applied on the available balance as of December 31, 2018 and fees related to letters of credit were estimated at the rate incurred on December 31, 2018; (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, 2018 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, 2018, we had approximately $300.0 million of bonds outstanding, with the majority related to plugging and abandonment obligations. The amounts are based on current market rates and conditions for these types of bonds and are subject to change. Excluded are potential increases in surety bond requirements which cannot be determined. 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 2018, our realized prices for crude oil increased 36.3%, NGLs increased 21.6% and natural gas increased 5.1% from 2017. 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 increased by 17.0% in 2018 compared to 2017. These operating costs related to production are impacted by factors other than inflation or deflation, such as workovers, facility repairs, PHA fees for certain fields (recorded as credits to expense), production levels, hurricanes, changes in regulations 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.

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. If crude oil and natural gas prices decrease, we may need to increase this liability. Also, disputes may arise as to volume measurements and allocation of production components between parties. These disputes could cause us to increase our liability for such potential exposure. We do not record receivables for those properties in which the Company has taken less than its ownership share of production which could cause us to delay recognition of amounts due us.

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), *Revenue from Contracts and Customers* (*Topic 606*). ASU 2014-09 amends and replaces current revenue recognition requirements, including most industry-specific guidance. The revised guidance establishes a five step approach to be utilized in determining when, and if, revenue should be recognized. ASU 2014-09 was effective for us for annual and interim periods beginning after December 15, 2017. ASU 2014-09 is more conceptual than previously issued guidance and covers virtually all industries, therefore, interpretation and judgment was required in applying ASU 2014-09 to our specific transactions. Our analysis and interpretations of ASU 2014-09 may be different than other companies in our industry. Upon adoption, an entity may elect one of two methods, either restatement of prior periods presented or recording a cumulative adjustment in the initial period of application (modified retrospective approach). Our analysis of contracts with customers against the requirements of ASU 2014-09 did not identified any changes to the timing of revenue recognition, or any changes to the classification of transactions previously recorded as revenue or credits to expense based on requirements of the standard, therefore no adjustments were recorded.

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 incurred significant ceiling test write-downs during 2016. We did not have any ceiling test impairments in 2018 or 2017. Ceiling test impairments in future periods are highly dependent on commodity prices, and also are impacted by other factors and events. See the *Overview* section for a discussion on the price sensitivity of the ceiling test under certain assumptions. For the effect of lower commodity prices on liquidity, see *Risk Factors - Risks Related to Financing* under Part I, Item 1A and in the *Liquidity and Capital Resources* section of this Item in this Form 10-K for additional information about our Credit Agreement and financing. 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, 2018 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. See the *Overview* section for a discussion on the price sensitivity of the ceiling test under certain assumptions and the resulting sensitivity to reserve quantities.

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.

Fair value measurements. We measure the fair value of our derivative financial instruments by applying the income approach and using inputs that are derived principally from observable market data. Changes in the underlying commodity prices of the derivatives impact the unrealized and realized gain or loss recognized. We do not apply hedge accounting to our derivatives; therefore, the change in fair value for all outstanding derivatives, which include derivatives that are entered into in anticipation of future production, are reflected currently in our statements of operations. This can create timing differences between when the production is recognized and when the gain or loss on the derivative is recognized in the income statement. We estimate the fair value of our debt based on trades when such information is available. The market for our debt has low volumes of activity and has experienced high volatility in the past; therefore, the fair values presented may not represent the fair value of our debt in future periods.

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.

Share-based compensation. We recognize compensation cost for share-based payments to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of the grant, which may be significantly different than on the date of vesting. We estimate forfeitures during the service period and make adjustments depending on actual experience. These adjustments can create timing differences on when expense is recognized.

Troubled Debt Restructuring. We accounted for the Exchange Transaction in 2016 as a troubled debt restructuring pursuant to the guidance under ASC 470-60 which requires the carrying value of the 2016 Debt to be measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the 2016 Debt in the Consolidated Statements of Operations from September 7, 2016 to October 18, 2018. Thus, our reported interest expense was significantly less than the contractual interest payments.

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 2018 and had open derivative contracts as of December 31, 2018. 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 9 – 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 2018 and assuming no other items had changed, our income before income tax would have decreased by approximately $58.0 million in 2018. If costs and expenses of operating our properties had increased by 10% in 2018, our income before income tax would have decreased by approximately $18.0 million in 2018. 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, 2018, we had $21.0 outstanding on our Credit Agreement. We had amounts outstanding during most of the fourth quarter of 2018 and no borrowings outstanding during the first three quarters of 2018. 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 2.50% to 3.50% depending on the amount outstanding. In 2018, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have changed $0.1 million during 2018. We did not have any derivative contracts related to interest rates as of December 31, 2018.

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

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

MA NAGEMENT'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, 2018 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, 2018 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, 2018, 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, 2018, 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, 2018 and 2017, and the related consolidated statements of operations, changes in shareholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2018, and related notes and our report dated February 28, 2019 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 W&T Offshore, Inc. and subsidiaries 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
February 28, 2019

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, 2018 and 2017, and the related consolidated statements of operations, changes in shareholders’ equity (deficit) and cash flows for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 February 28, 2019 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.

/s/ Ernst & Young LLP

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

Houston, Texas
February 28, 2019

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

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 33,293	$ 99,058
Receivables:		
Oil and natural gas sales	47,804	45,443
Joint interest, net	14,634	19,754
Income taxes	54,076	13,006
Total receivables	116,514	78,203
Prepaid expenses and other assets (Note 1)	76,406	13,419
Total current assets	226,213	190,680
Oil and natural gas properties and other, net – at cost: (Note 1)	515,421	579,016
Restricted deposits for asset retirement obligations	15,685	25,394
Income tax receivables	—	52,097
Other assets (Note 1)	91,547	60,393
Total assets	$ 848,866	$ 907,580
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$ 82,067	$ 79,667
Undistributed oil and natural gas proceeds	28,995	20,129
Advances from joint interest partners	20,627	3,998
Asset retirement obligations	24,994	23,613
Long-term debt	—	22,925
Accrued liabilities (Note 1)	29,611	17,930
Total current liabilities	186,294	168,262
Long-term debt: (Note 2)		
Principal	646,000	889,790
Carrying value adjustments	(12,465)	79,337
Long-term debt, less current portion – carrying value	633,535	969,127
Asset retirement obligations, less current portion	285,143	276,833
Other liabilities (Note 1)	68,690	66,866
Commitments and contingencies (Note 18)	—	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at December 31, 2018 and December 31, 2017	—	—
Common stock, $0.00001 par value; 200,000,000 shares authorized; 143,513,206 issued and 140,644,033 outstanding at December 31, 2018 and 141,960,462 issued and 139,091,289 outstanding at December 31, 2017	1	1
Additional paid-in capital	545,705	545,820
Retained earnings (deficit)	(846,335)	(1,095,162)
Treasury stock, at cost; 2,869,173 shares at December 31, 2018 and December 31, 2017	(24,167)	(24,167)
Total shareholders' deficit	(324,796)	(573,508)
Total liabilities and shareholders' deficit	$ 848,866	$ 907,580

See accompanying notes.

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

	Year Ended December 31,		
	2018	**2017**	**2016**
Revenues:			
Oil	$ 438,798	$ 340,010	$ 268,950
NGLs	37,127	32,257	26,429
Natural gas	99,629	108,923	100,405
Other	5,152	5,906	4,202
Total revenues	580,706	487,096	399,986
Operating costs and expenses:			
Lease operating expenses	153,262	143,738	152,399
Production taxes	1,832	1,740	1,889
Gathering and transportation	22,382	20,441	22,928
Depreciation, depletion and amortization	131,423	138,510	194,038
Asset retirement obligations accretion	18,431	17,172	17,571
Ceiling test write-down of oil and natural gas properties	—	—	279,063
General and administrative expenses	60,147	59,744	59,740
Derivative (gain) loss	(53,798)	(4,199)	2,926
Total costs and expenses	333,679	377,146	730,554
Operating income (loss)	247,027	109,950	(330,568)
Interest expense, net	48,645	45,521	84,382
Gain on debt transactions	47,109	7,811	123,923
Other (income) expense, net	(3,871)	5,127	1,369
Income (loss) before income tax expense (benefit)	249,362	67,113	(292,396)
Income tax expense (benefit)	535	(12,569)	(43,376)
Net income (loss)	$ 248,827	$ 79,682	$ (249,020)
Basic and diluted earnings (loss) per common share	$ 1.72	$ 0.56	$ (2.60)

See accompanying notes.

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

	Common Stock Outstanding		Additional Paid-In Capital	Retained Earnings (Deficit)	Treasury Stock		Total Shareholders' Equity (Deficit)
	Shares	Value			Shares	Value	
Balances at December 31, 2015	76,506	$ 1	$ 423,499	$ (925,824)	2,869	$ (24,167)	$ (526,491)
Share-based compensation	—	—	11,013	—	—	—	11,013
Stock issued	61,168	—	106,366	—	—	—	106,366
RSUs and shares surrendered for payroll taxes	—	—	(905)	—	—	—	(905)
Net loss	—	—	—	(249,020)	—	—	(249,020)
Balances at December 31, 2016	137,674	1	539,973	(1,174,844)	2,869	(24,167)	(659,037)
Share-based compensation	—	—	7,191	—	—	—	7,191
Stock issued	1,417	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(1,344)	—	—	—	(1,344)
Net income	—	—	—	79,682	—	—	79,682
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)

See accompanying notes.

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

	Year Ended December 31, 2018	2017	2016
Operating activities:			
Net income (loss)	$ 248,827	$ 79,682	$ (249,020)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	149,854	155,682	211,609
Ceiling test write-down of oil and gas properties	—	—	279,063
Gain on debt transactions	(47,109)	(7,811)	(123,923)
Amortization and write-offs of debt items	2,850	1,715	2,548
Share-based compensation	3,540	7,191	11,013
Derivative (gain) loss	(53,798)	(4,199)	2,926
Derivatives cash (payments) receipts, net	(28,164)	4,199	4,746
Deferred income taxes	500	217	28,392
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(2,361)	(2,370)	(7,005)
Joint interest receivables	5,120	2,131	12
Insurance reimbursements	—	31,740	—
Income taxes	11,028	(1,063)	(64,274)
Prepaid expenses and other assets	3,383	3,238	(14,946)
Escrow deposit - Apache lawsuit	—	(49,500)	—
Asset retirement obligation settlements	(28,617)	(72,409)	(72,320)
Cash advances from JV partners	16,629	(437)	4,420
Accounts payable, accrued liabilities and other	40,081	11,402	939
Net cash provided by operating activities	321,763	159,408	14,180
Investing activities:			
Investment in oil and natural gas properties and equipment	(106,191)	(106,174)	(83,800)
Acquisition of property interest	(16,782)	—	—
Proceeds from sales of assets, net	56,588	—	1,500
Purchases of furniture, fixtures and other	—	(933)	(96)
Net cash used in investing activities	(66,385)	(107,107)	(82,396)
Financing activities:			
Borrowings on credit facility	61,000	—	340,000
Repayments on credit facility	(40,000)	—	(340,000)
Issuance of Senior Second Lien Notes	625,000	—	—
Issuance of 1.5 Lien Term Loan	—	—	75,000
Extinguishment of debt – principal	(903,194)	—	—
Extinguishment of debt – premiums	(21,850)	—	—
Payment of interest on 1.5 Lien Term Loan	(6,623)	(8,227)	(2,570)
Payment of interest on 2nd Lien PIK Toggle Notes	(9,725)	(7,335)	—
Payment of interest on 3rd Lien PIK Toggle Notes	(4,672)	(6,201)	—
Debt transactions costs	(17,457)	(421)	(18,464)
Other	(3,622)	(1,295)	(928)
Net cash (used in) provided by financing activities	(321,143)	(23,479)	53,038
(Decrease) increase in cash and cash equivalents	(65,765)	28,822	(15,178)
Cash and cash equivalents, beginning of period	99,058	70,236	85,414
Cash and cash equivalents, end of period	$ 33,293	$ 99,058	$ 70,236

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.

Recent Events

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 improved in 2018 compared to the average realized prices in 2017.

In October 2018, we substantially changed our capital structure through the issuance of secured senior notes, which when combined with cash on hand, funded the repurchasing and retirement, repayment or redemption of all of the prior debt instruments. This transaction reduced the amount of debt outstanding and extended debt maturities with the new debt instruments maturing on November 1, 2023. In addition, we entered into the Sixth Amended and Restated Credit Agreement (the "Credit Agreement"), which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million. See Note 2 for additional information.

We have assessed our financial condition, the current capital markets and options given different scenarios of commodity prices. We believe we will have adequate liquidity to fund our operations through February 2020, the period of assessment to qualify as a going concern. However, we cannot predict the potential changes in commodity prices, which could affect our operations, liquidity levels and compliance with debt obligations.

Reclassification

Certain reclassifications have been made to prior periods' financial statements to conform to the current year presentation as follows: In the Consolidated Statements of Operations, interest income was reclassified from *Other (income) expense, net* to *Interest expense, net*, and amounts related to capitalized interest are included in the line *Interest expense, net.* Neither of these reclassifications changed *Net income (loss) before income tax expense (benefit).* In the Consolidated Statements of Cash Flows, within the *Net cash provided by operating activities* and the *Net cash used in investing activities* sections, adjustments were made to certain line items, of which did not change the total amounts previously reported. These adjustments did not affect the Consolidated Balance Sheets.

Accounting Standard Updates Effective January 1, 2018

Accounting Standards Update No. 2017-01, Business Combinations (Topic 805) – Clarifying the Definition of a Business ("ASU 2017-01"), became effective for us as of January 1, 2018. The new guidance is intended to assist with the evaluation of whether a set of transferred assets and activities is a business. In application of the revised guidance under ASU 2017-01 for our acquisition of a non-operated interest in the Heidelberg field described in Note 5, we determined the transaction should be treated as an asset purchase rather than the purchase of a business.

Accounting Standard Update No. 2014-09, Revenue from Customers (Topic 606) ("ASU 2014-09"), became effective for us asof January 1, 2018. We reviewed our contracts using the five-step revenue recognition model, which did not identify any changes required as to the amount or timing of revenue recognition. We adopted the new standard using the modified retrospective approach which did not result in any cumulative-effect adjustment on the date of adoption. The implementation of ASU 2014-09 resulted in a change in our reporting in the Consolidated Statements of Operations and we report revenue streams separately for crude oil, NGLs, natural gas and other revenues in compliance with the new standard.

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, 2018 and 2017, $4.1 million and $4.7 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, large financial institutions and large trading houses. 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,		
	2018	2017	2016
Customer			
Shell Trading (US) Co.	30%	46%	43%
BP Products North America	20%	**	**
Vitol Inc.	14%	15%	20%

** 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 Bad Debts

Our accounts receivables are recorded at their historical cost, less an allowance for doubtful accounts. 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. We have not had any significant problems collecting our receivables from our customers, but with the decline in commodity prices starting in 2015, several oil and gas companies have filed for bankruptcy where we have joint interest arrangements. We use the specific identification method of determining if an allowance for doubtful accounts is needed. The following table describes the balance and changes to the allowance for doubtful accounts:

	2018	2017	2016
Allowance for doubtful accounts, beginning of period	$ 9,114	$ 7,602	$ 2,490
Additional provisions for the year	1,233	1,512	5,112
Uncollectable accounts written off	(655)	—	—
Allowance for doubtful accounts, end of period	$ 9,692	$ 9,114	$ 7,602

Insurance Receivables

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs primarily as a result of hurricane damage when we deem those to be probable of collection, which normally arises when our insurance company's adjuster reviews and approves such costs for payment or when the insurance company has agreed to reimbursement amounts. Claims that have been processed in this manner have customarily been paid on a timely basis. During 2017, we received payments by certain insurance companies related to settlement of previously unpaid claims. See Note 7 for additional information.

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 describes the major items for the periods presented:

	Year Ended December 31,	
	2018	2017
Derivatives – current (1)	$ 60,687	$ —
Prepaid/accrued insurance	2,987	2,401
Surety bonds unamortized premiums	2,210	2,676
Prepaid deposits related to royalties	8,872	6,456
Advances for capital expenditures	745	—
Other	905	1,886
Prepaid expenses and other assets	$ 76,406	$ 13,419

(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. 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 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.

We capitalize interest on the amount of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. Capitalization of interest ceases when the property is moved into the amortization base. All capitalized interest is recorded within *Oil and natural gas property and other, net* on the Consolidated Balance Sheets.

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.

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 equipment are recorded at cost using the full-cost method.

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,	
	2018	2017
Oil and natural gas properties and equipment	$ 8,169,871	$ 8,102,044
Furniture, fixtures and other	20,228	21,831
Total property and equipment	8,190,099	8,123,875
Less accumulated depreciation, depletion and amortization	7,674,678	7,544,859
Oil and natural gas properties and other, net	$ 515,421	$ 579,016

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 2018 or 2017. We recorded ceiling test write-downs in 2016, which was reported as a separate line in the Statements of Operations, due primarily to declines in the unweighted rolling 12-month average of first-day-of-the-month commodity prices for oil and natural gas. The ceiling test write-downs of the carrying value of our oil and natural gas properties was $279.1 million for 2016. If average crude oil and natural gas prices decrease significantly, it is possible that ceiling test write-downs could be recorded during 2019 or 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 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. 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 20 for additional information about our proved reserves.

Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices. From time to time, we use 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 2018 and 2017, and as of December 31, 2018, 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 2018 and 2017, 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. Changes in a derivative's fair value are required to be recognized currently in earnings unless specific hedge accounting and documentation criteria are met at the time the derivative contract is entered into. Whenever we have entered into derivative contracts, we did not designate our derivatives instruments as hedging instruments, therefore, all changes in fair value are recognized in earnings.

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. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense. See Note 13 for additional information.

Other Assets (long-term)

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

	December 31,			
	2018		2017	
Escrow deposit – Apache lawsuit	$	49,500	$	49,500
Appeal bond deposits		6,925		6,925
Unamortized debt issuance costs		4,773		330
Investment in White Cap, LLC		2,586		2,511
Derivatives		21,275		—
Unamortized brokerage fee for Monza		2,277		—
Proportional consolidation of Monza's other assets (Note 4)		3,275		—
Other		936		1,127
Total other assets	$	91,547	$	60,393

Accrued Liabilities

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

	December 31,			
	2018		2017	
Accrued interest	$	12,385	$	4,200
Accrued salaries/payroll taxes/benefits		2,320		2,454
Incentive compensation plans		10,817		7,366
Litigation accruals		3,673		3,480
Other		416		430
Total accrued liabilities	$	29,611	$	17,930

Debt Issued During 2016

We accounted for a debt exchange transaction in 2016, which is described in Note 2, as a troubled debt restructuring pursuant to the guidance under Accounting Standard Codification 470-60, *Troubled Debt Restructuring* (“ASC 470-60”). Under ASC 470-60, the carrying value of the debt issued during 2016 (as described in Note 2) is measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the debt issued in 2016 in the Consolidated Statements of Operations since September 7, 2016 through October 18, 2018. Additionally, interest paid related to the debt issued in 2016 was classified as a financing activity in the Consolidated Statements of Cash Flows as required under ASC 470-60. See Note 2 for additional information.

Debt Issuance Costs

Debt issuance costs associated with our 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 is reported as a reduction in *Long-term debt, less current portion – carrying value* in the Consolidated Balance Sheets. See Note 2 for additional information.

Premiums Received and Discounts Provided on Debt Issuance

Premiums and discounts were recorded in *Long-term debt, less current portion – 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 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. The gains recorded in 2017 and 2016 of $7.8 million and $123.9 million, respectively, relate to the debt exchange transaction occurring during 2016. Differences in the utilization of the payment-in-kind option during 2017 resulted in adjustments to the gain previously recorded in 2016. 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, 2018	December 31, 2017
Apache lawsuit	$ 49,500	$ 49,500
Uncertain tax positions including interest/penalties	11,523	11,015
Dispute related to royalty deductions	4,787	—
Dispute related to royalty-in-kind	2,135	914
Other	745	5,437
Total other liabilities (long-term)	$ 68,690	$ 66,866

Share-Based Compensation

Compensation cost for share-based payments to employees and non-employee directors is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which the recipient is required to provide service in exchange for the award. The fair value for equity instruments subject to only time or to Company performance measures was determined using the closing price of the Company's common stock at the date of grant. We recognize share-based compensation expense on a straight line basis over the period during which the recipient is required to provide service in exchange for the award. Estimates are made for forfeitures during the vesting period, resulting in the recognition of compensation cost only for those awards that are estimated to vest and estimated forfeitures are adjusted to actual forfeitures when the equity instrument vests. See Note 11 for additional information.

Other (Income) Expense, Net

For 2018, the amount consists 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 (as defined in Note 4). For 2017, the amount consists primarily of expense items related to the Apache lawsuit of $6.3 million, partially offset by loss-of-use reimbursements from a third-party for damages incurred at one of our platforms of $1.1 million. For 2016, the amount consists primarily of write-offs of debt issuance costs.

Earnings (Loss) 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 (loss) per share under the two-class method when the effect is dilutive. See Note 14 for additional information.

Recent Accounting Developments

In February 2016, the FASB issued Accounting Standards Update No. 2016-02,*Leases* (*Topic 842*) ("ASU 2016-02"). Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Consistent with current GAAP, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a financing or operating lease. However, unlike current GAAP, which requires only capital or financing leases to be recognized on the balance sheet, ASU 2016-02 will require both types of leases to be recognized on the balance sheet. ASU 2016-02 also will require disclosures to help investors and other financial statement users to better understand the amount, timing and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative requirements, providing additional information about the amounts recorded in the financial statements. ASU 2016-02 does not apply for leases for oil and gas properties, but does apply to equipment used to explore and develop oil and gas resources. ASU 2016-02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective or the full retrospective approach. We expect to adopt ASU 2016-02 using the modified retrospective approach. Our current operating lease that will be impacted by ASU 2016-02 is our lease for office space, which is in Houston, Texas and will result in an increase in assets and liabilities of approximately $5.0 million. Although we did not identify other arrangements impacted by ASU 2016-02, future arrangements related to equipment may be impacted depending on the facts and circumstances. As of December 31, 2018, we did not have any leases classified as financing leases.

In June 2016, the FASB issued Accounting Standards Update No. 2016-13,*Financial Instruments – Credit Losses* (*Topic 326*) ("ASU 2016-13"). 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. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019 and early adoption is permitted for fiscal years beginning after December 15, 2018. We have not yet fully determined or quantified the effect ASU 2016-13 will have on our financial statements.

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"). 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. ASU 2017-12 is effective for fiscal years beginning after December 15, 2019 and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, including adoption in an interim period. As we do not designate our commodity derivative instruments as qualifying hedging instruments, our assessment is this amendment will not impact the presentation of the changes in fair values of our commodity derivative instruments on our financial statements.

2. Long-Term Debt

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

	December 31, 2018			December 31, 2017		
	Principal	Adjustments to Carrying Value (1)	Carrying Value	Principal	Adjustments to Carrying Value (2)	Carrying Value
Credit Facility, due October 2022	$ 21,000	$ —	$ 21,000	$ —	$ —	$ —
9.75 % Senior Second Lien Notes, due November 2023:	625,000	(12,465)	612,535	—	—	—
11.00% 1.5 Lien Term Loan, due November 2019:	—	—	—	75,000	15,596	90,596
9.00 % Second Lien Term Loan, due May 2020:	—	—	—	300,000	(4,381)	295,619
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020:	—	—	—	171,769	40,617	212,386
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021:	—	—	—	153,192	50,005	203,197
8.50% Unsecured Senior Notes, due June 2019	—	—	—	189,829	425	190,254
Total long-term debt	646,000	(12,465)	633,535	889,790	102,262	992,052
Current maturities of long-term debt (3)	—	—	—	—	22,925	22,925
Long term debt, less current maturities	$ 646,000	$ (12,465)	$ 633,535	$ 889,790	$ 79,337	$ 969,127

(1) Unamortized debt issuance costs.
(2) Unamortized debt issuance costs, unamortized debt premiums, unamortized debt discounts, future interest payments for certain debt instruments and future payments-in-kind ("PIK") for certain debt instruments recorded on an undiscounted basis.
(3) Future interest payments due within twelve months on the 1.5 Lien Term Loan, Second Lien PIK Toggle Notes and Third Lien PIK Toggle Notes (these debt instruments are defined below).

Aggregate annual maturities of amounts recorded for long-term debt as of December 31, 2018 are as follows (in millions): 2019–$0.0; 2020–$0.0; 2021–$0.0; 2022–$21.0; 2023-$625.0. See below for a discussion of our debt instruments.

9.75% Senior Second Lien Notes Due 2023

On October 18, 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, 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”). 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, beginning on May 1, 2019.

Prior to November 1, 2020, we may redeem all or any portion of the Senior Second Lien Notes at a redemption price equal to 100% of the principal amount of the outstanding Senior Second Lien Notes plus accrued and unpaid interest, if any, to the redemption date, plus the “Applicable Premium” (as defined in the Indenture). In addition, prior to November 1, 2020, we may, at our option, on one or more occasions redeem up to 35% of the aggregate original principal amount of the Senior Second Lien Notes in an amount not greater than the net cash proceeds from certain equity offerings at a redemption price of 109.750% of the principal amount of the outstanding Senior Second Lien Notes plus accrued and unpaid interest, if any, to the redemption date.

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 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.

Certain entities controlled by Tracy W. Krohn, Chairman, Chief Executive Officer and President of the Company, and his family were invested in certain existing notes of the Company that were repurchased by the Company in connection with the Refinancing Transaction (defined below). The Krohn entities tendered their existing notes on the same terms as were made available to all other holders of the existing notes pursuant to the publicly disclosed Company offer to purchase any and all such notes and reinvested an amount approximately equal to the proceeds from such tenders by purchasing approximately $8.0 million principal in Senior Second Lien Notes at the same price offered to other initial investors in the offering of such notes. As part of the 2018 Refinancing Transaction, the Krohn entities also had their previously disclosed $5.0 million investment in the Company’s Second Lien Term Loan (defined below) liquidated as the loan was repaid in full.

The Senior Second Lien Notes are secured by a second-priority lien on all of our assets that are secured under the Credit Agreement. The Senior Second Lien Notes contain covenants that limit or prohibit our ability and the ability of certain of our subsidiaries to: (i) make investments; (ii) incur additional indebtedness or issue certain types of preferred stock; (iii) create certain liens; (iv) sell assets; (v) enter into agreements that restrict dividends or other payments from the Company’s subsidiaries to the Company; (vi) consolidate, merge or transfer all or substantially all of the assets of the Company; (vii) engage in transactions with affiliates; (viii) pay dividends or make other distributions on capital stock or subordinated indebtedness; and (ix) create subsidiaries that would not be restricted by the covenants of the Indenture entered into by and among the Company, the Guarantors, and Wilmington Trust, National Association, as trustee (the “Trustee”). 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 entered into the Credit Agreement with a maturity date of October 18, 2022. The primary items of the Credit Agreement are as follows, with certain terms defined under the Credit Agreement:

- The initial borrowing base and lending commitment is $250.0 million.
- Letters of credit may be issued in amounts up to $30.0 million, provided availability under the Credit Agreement exists.
- The Leverage Ratio, as defined in the Credit Agreement, is limited to 3.50 to 1.00 for quarters ending December 31, 2018 and March 31, 2019; 3.25 to 1.00 for quarters ending June 30, 2019 and September 30, 2019; and 3.00 to 1.00 for quarters ending December 31, 2019 and thereafter. In the event of a Material Acquisition, as defined in the Credit Agreement, the Leverage Ratio limit is 3.50 to 1.00 for the two quarters following a Material Acquisition.
- 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.
- To the extent there are borrowings, the Applicable Margins, as defined in the Credit Agreement, for Eurodollar Loans range from 2.50% to 3.50% per annum and the Applicable Margins for ABR loans range from 1.50% to 2.50% per annum. The specific Applicable Margin rate is based on the Borrowing Base Utilization Percentage.
- The commitment fee is 37.5 basis points if the Borrowing Base Utilization Percentage is below 50% and 50 basis points if the Borrowing Base Utilization Percentage is 50% or greater.
- We were 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 by December 2, 2018 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.

As of December 31, 2018, we had $21.0 million borrowings outstanding under the Credit Agreement and as of December 31, 2017, we had no borrowings outstanding under the Fifth Amended and Restated Credit Agreement, as amended (the "Prior Credit Agreement). As of December 31, 2018 and 2017, we had $9.6 million and $0.3 million, respectively, outstanding in letters of credit under the Credit Agreement and Prior Credit Agreement, respectively.

As of December 31, 2018, we were in compliance with all applicable covenants of the Credit Agreement and Senior Second Lien Notes.

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

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.
- 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.

Exchange Transaction in 2016

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our Unsecured Senior Notes for: (i) $159.8 million in aggregate principal amount of Second Lien PIK Toggle Notes; (ii) $142.0 million in aggregate principal amount of Third Lien PIK Toggle Notes; and (iii) 60.4 million shares of our common stock (collectively, the "Debt Exchange"). At the same time on closing on the Debt Exchange, we closed on a $75.0 million, 1.5 Lien Term Loan, with the then largest holder of our Unsecured Senior Notes (collectively with the Debt Exchange, the "Exchange Transaction"). We accounted for the Exchange Transaction as a Troubled Debt Restructuring pursuant to the guidance under ASC 470-60. Under ASC 470-60, the carrying value of the Second Lien PIK Toggle Notes, Third Lien PIK Toggle Notes and 1.5 Lien Term Loan (the "2016 Debt") was measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the 2016 Debt in the Consolidated Statements of Operations from September 7, 2016 to October 18, 2018. Therefore, our reported interest expense was significantly less than the contractual interest payments for the period the 2016 Debt was outstanding. Under ASC 470-60, payments related to the 2016 Debt are reported in the financing section of the Condensed Consolidated Statements of Cash Flows.

A gain of $123.9 million was recognized related to the Exchange Transaction during 2016. Under ASC 470-60, a gain was recognized as the sum of (i) the future undiscounted payments (principal and interest) related to the 2016 Debt, (ii) the fair value of the common stock issued and (iii) deal transaction costs of $18.9 million was less than the sum of (iv) the carrying value of the Unsecured Senior Notes exchanged and (v) the funds received from the 1.5 Lien Term Loan. The shares of common stock issued were valued at $1.76 per share, which was the closing price on September 7, 2016. The effect on both basic and diluted earnings per share for 2016 was $1.30 per share, which assumes the gain would not affect our income tax benefit for 2016.

During the second quarter of 2017, interest on the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes was paid in cash rather than in kind. As a result of the cash interest payment, an $8.2 million net reduction was recorded to long-term debt on the Consolidated Balance Sheet and the offset to *Gain on Debt Transactions* in the Consolidated Statement of Operations. For 2017, $0.4 million of additional expense was recorded to *Gain on Debt Transactions* for differences between actual and estimated transaction expenses. The effect of these transactions on both basic and diluted earnings per share for 2017 was $0.06 per share, which assumes the net gain would not affect our income tax benefit for that period.

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

		December 31,	
	Hierarchy	2018	2017
Assets:			
Derivatives – open contracts	Level 2	$ 74,580	$ —
Liabilities:			
9.75% Senior Second Lien Notes, due November 2023	Level 2	$ 546,875	$ —
11.00% 1.5 Lien Term Loan, due November 2019	Level 2	—	75,000
9.00 % Second Lien Term Loan, due May 2020	Level 2	—	288,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020	Level 2	—	162,322
8.50%/10.00% Third Lien PIK Toggle Notes due June 2021	Level 2	—	119,490
8.50% Unsecured Senior Notes, due June 2019	Level 2	—	178,439
Credit Agreement	Level 2	21,000	—

As of December 31, 2018, the carrying value of our open derivative contracts equaled the estimated fair value, and as of December 31, 2017, we did not have any open derivative contracts. 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 for the fair value measurement 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 long-term debt 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.

The carrying value of our long-term debt is disclosed in Note 2 above.

4. Joint Venture Drilling Program

On March 12, 2018, W&T and two other initial members formed and initially funded a limited liability company, Monza Energy LLC, a Delaware limited liability company, that will jointly participate with us in the exploration, drilling and development of up to 14 identified drilling projects (the "JV Drilling Program") in the Gulf of Mexico over the next three years. W&T initially contributed 88.94% of its working interest in 14 identified undeveloped drilling projects to Monza and retained 11.06% of its working interest. The Monza board approved the substitution of one of these identified undeveloped drilling projects, the Viosca Knoll 823 ("Virgo") A-14 well, with the Virgo A-13 well, which was contributed to Monza through the conveyance by W&T of 58.71% of its working interest in such well to Monza and retaining 41.29% of its working interest in such well. The interest in the Virgo A-14 well was reconveyed to W&T. Since the initial closing, additional investors have joined as members of Monza and as of December 31, 2018, total commitments by all members, including W&T, were $361.4 million. Monza closed off funding from additional investors. The JV 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. For one well in the JV Drilling Program, a modification was approved exempting W&T from funding certain cost overruns and W&T is receiving 20% of the revenues less expenses of its prior interest on a combined basis, which removes W&T's promote in this well. W&T will be the operator of each well in the JV Drilling Program unless there is already a designated third-party operator.

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, Chief Executive Officer and President. 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.

At the inception of Monza, W&T received a net reimbursement of approximately $20.0 million for the capital expenditures incurred prior to the close date for projects in the JV Drilling Program. W&T may be obligated to fund certain cost overruns, subject to certain exceptions, on JV Drilling Program wells above budgeted and contingency amounts. As of December 31, 2018, members of Monza made partner capital contribution payments to Monza totaling $114.7 million.

Information on the structure and relationship follows:

Board Structure and Authority

Under the Monza limited liability agreement, the business and affairs of Monza are managed by a board of five directors, which will consist of three directors selected by the third-party investors, Mr. Krohn, and an additional independent director will be selected by a majority of the third-party investors in Monza subject to consent by W&T. The independent director and one of the directors to be selected by the investors have not yet been selected. The day-to-day operations of Monza are being managed by W&T, under the direction of the Monza board, pursuant to a services agreement. W&T has no control over the decisions of the Monza board. W&T has veto rights for certain decisions, but does not have the ability to unilaterally make decisions for Monza, except for day-to-day decisions as permitted under the services agreement. The Monza board is responsible for the management of Monza and for making decisions with respect to its interest in the 14 drilling projects, including approval of the budgets.

Accounting Methodology and Carrying Amounts

Our interest in Monza is considered to be a variable interest entity that we account for using proportional consolidation. We do not fully consolidate Monza because we are not considered the primary beneficiary and we utilize proportional consolidation to account for our interest in the Monza properties. As of December 31, 2018, in the Consolidated Balance Sheet, we recorded $8.8 million, net, in oil and natural gas properties, $3.3 million in other assets and $0.7 million, net, increase in working capital in connection with our proportional interest in Monza's assets and liabilities. For the year ended December 31, 2018, we recorded $4.3 million in revenue, $2.3 million in operating expense and $0.2 million, net, in other expense in connection with our proportional interest in Monza's operations.

Maximum Exposure

Our contribution to Monza as of December 31, 2018 was $53.0 million, which consisted of net cash and the conveyance of the Company's working interest in the 14 projects. We may also take responsibility for certain drilling and completion cost overruns, subject to certain limitations and certain exceptions, of which the total exposure cannot be estimated at this time.

5. Acquisitions and Divestitures

Heidelberg Field

On April 5, 2018, we closed on the purchase from Cobalt International Energy, Inc. of a 9.375% non-operated working interest in the Heidelberg field located in Green Canyon blocks 859, 903 and 904. The gross purchase price was $31.1 million which was adjusted for certain closing items and an effective date of January 1, 2018. Cash flows generated by the acquired interest between the effective date and the closing date reduced the net purchase price to $16.8 million. 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 closed on 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 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 liability (in thousands):

	Year Ended December 31, 2018	Year Ended December 31, 2017
Asset retirement obligations, beginning of period	$ 300,446	$ 334,438
Liabilities settled	(28,617)	(72,409)
Accretion of discount	18,431	17,172
Liabilities incurred and assumed through acquisition	4,286	163
Revisions of estimated liabilities (1) (2)	15,591	21,082
Asset retirement obligations, end of period	310,137	300,446
Less current portion	24,994	23,613
Long-term	$ 285,143	$ 276,833

(1) Revisions in 2018 reflect cost estimate increases as a result of new data on the required scope of work becoming available to us through 2018. This new data included data realized during the planning phase of the projects, and as the projects proceeded through the execution phase. This new data indicated that the scope was larger and more difficult than the scope used for end of 2017 estimates. As an example, larger heavy lift vessels would be needed for certain platform removals, and certain wells needed additional well plugging operations to complete the decommissioning per agency requirements.

(2) Revisions in 2017 were primarily related to increased costs associated with wells at four fields that experienced sustained casing pressure issues. Wells that experience sustained casing pressure require more days and greater work scope to complete the abandonment project. Partially offsetting are downward revisions to cost estimates from service providers for plug and abandonment work at certain locations.

7. Insurance Claims

During the third quarter of 2008, Hurricane Ike caused substantial damage to certain of our properties. Our insurance policies in effect on the occurrence date of Hurricane Ike had a retention requirement of $10.0 million per occurrence, which has been satisfied, and coverage policy limits of $150.0 million for property damage due to named windstorms (excluding damage at certain facilities) and $250.0 million for, among other things, removal of wreckage if mandated by any governmental authority.

During 2017 and 2016, we received insurance reimbursements of $31.7 million and $10.2 million, respectively, primarily related to hurricane damage. Cash receipts from insurance proceeds are included within *Net cash provided by operating activities* in the Consolidated Statements of Cash Flows and are primarily recorded as reductions in *Oil and natural gas properties and other, net* on the Consolidated Balance Sheets, with some amounts recorded as reductions in *Lease operating expense*, *General and administrative expenses* and *Other income (expense), net* in the Consolidated Statements of Operations. From the third quarter of 2008 through December 31, 2018, we have received $203.1 million cumulative reimbursements from insurance companies related to hurricane reimbursements. As of December 31, 2018, there were no outstanding hurricane claims.

8. Restricted Deposits

Restricted deposits as of December 31, 2018 and 2017 consisted of funds escrowed for collateral related to the future plugging and abandonment obligations of certain oil and natural gas properties.

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

9. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and, from time to time, we use various derivative instruments to manage our exposure to this commodity price risk from sales of our oil and natural gas. We are exposed to credit loss in the event of nonperformance by the derivative counterparties; however, we currently anticipate that each of our derivative counterparties will be able to fulfill their contractual obligations. Additional collateral was not required by us and we do not require collateral from our derivative counterparties.

Each derivative contract is recorded on the balance sheet as an asset or liability at fair value as of the respective period. We have elected not to designate our commodity derivative contracts as hedging instruments; therefore, all changes in the fair value of derivative contracts were recognized currently in earnings during the periods presented. While these contracts are intended to reduce the effects of price volatility, they may have limited incremental income from favorable price movements.

Commodity Derivatives

During 2018 and 2017, 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, 2018 are presented in the following tables:

Crude Oil: Swap, Priced off WTI (NYMEX)

Termination Period	Notional (1) Quantity (Bbls/day)	Notional (1) Quantity (Bbls)	Strike Price
May 2020	1,500	775,500	$ 60.80
May 2020	5,000	2,585,000	61.00
May 2020	3,500	1,809,500	60.85

(1) Bbls = Barrels

Crude Oil: Calls - Bought, Priced off WTI (NYMEX)

Termination Period	Notional (1) Quantity (Bbls/day)	Notional (1) Quantity (Bbls)	Strike Price
May 2020	10,000	5,170,000	$ 61.00

(1) Bbls = Barrels

Natural Gas: Two-way collars, Priced off Henry Hub (NYMEX)

Termination Period	Notional (2) Quantity (MMBtu/day)	Notional (2) Quantity (MMBtu)	Put Option Strike Price (Bought)	Call Option Strike Price (Sold)
June 2019	50,000	7,500,000	$ 2.49	$ 3.975

(2) MMBtu = Million British Thermal Units

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, 2018	December 31, 2017
Prepaid and other assets – current	$ 60,687	$ —
Other assets – non-current	21,275	—

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, 2018	2017	2016
Derivative (gain) loss	$ (53,798)	$ (4,199)	$ 2,926

Cash (payments) receipts, 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, 2018	2017	2016
Derivative cash (payments) receipts, net	$ (28,164)	$ 4,199	$ 4,746

10. Equity Transactions

During 2016, after receiving shareholder approval, the Company increased the amount of common stock authorized from 118.3million shares to 200.0 million shares, which allowed for the issuance of 60.4 million additional shares in conjunction with the Exchange Transaction executed during 2016.

During 2018, 2017 and 2016, we did not pay any dividends and dividends are currently suspended.

11. Share-Based Awards and Cash-Based Awards

Incentive Compensation Plan

The W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, and subsequent amendments, (the “Plan”) was approved by our shareholders. The Plan covers the Company’s eligible employees and consultants and includes both cash and share-based compensation awards. The Plan grants the Compensation Committee of the Board of Directors administrative authority over all participants, and grants the Chief Executive Officer (“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 “Committee”).

Pursuant to the terms of the Plan, the 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 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 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 2018, 2017 and 2016, the Company granted RSUs under the Plan to certain of its employees. 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. In addition to share-based awards, the Company may grant to its employees cash-based incentive awards under the Plan, which are both a short-term and long-term compensation components and are subject to satisfaction of certain predetermined performance criteria.

As of December 31, 2018, there were 11,852,592 shares of common stock available for issuance in satisfaction of awards under the Plan. The shares available for issuance are reduced on a one-for-one basis when RSUs are settled in shares of common stock, net of withholding tax. The Company has the option following vesting to settle RSUs in stock or cash, or a combination of stock and cash. During 2018, shares of common stock were used to settle all vested RSUs. During 2017, cash was used to settle vested RSUs related to the retirement of an executive officer and shares of common stock were used to settle all other vested RSUs. The Company expects to settle RSUs that vest in the future using shares of common stock.

RSUs currently outstanding relate to the 2018 and 2017 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 2018, 2017 and 2016 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 2018, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items ("Adjusted EBITDA") for 2018 and (ii) Adjusted EBITDA as a percent of total revenue ("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.

During 2017, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2017 and (ii) Adjusted EBITDA Margin for 2017. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2017, the Company achieved target for both Adjusted EBITDA and Adjusted EBITDA Margin.

During 2016, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2016 and (ii) Adjusted EBITDA Margin for 2016. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2016, the Company was below target for Adjusted EBITDA and achieved target for Adjusted EBITDA Margin.

A summary of activity related to RSUs is as follows:

	2018		2017		2016	
	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	5,765,251	$ 2.48	6,107,248	$ 2.73	3,474,079	$ 7.42
Granted	988,955	6.90	2,128,879	2.76	4,213,964	2.21
Vested	(2,261,665)	2.21	(2,108,553)	3.45	(968,652)	16.69
Forfeited	(1,136,624)	2.68	(362,323)	2.87	(612,143)	3.64
Nonvested, end of period	3,355,917	$ 3.90	5,765,251	$ 2.48	6,107,248	$ 2.73

Subject to the satisfaction of service conditions, the RSUs outstanding as of December 31, 2018 are eligible to vest in the year indicated in the table below:

	Restricted Stock Units
2019	2,429,006
2020	926,911
Total	3,355,917

RSUs fair value at grant date - During 2018, 2017 and 2016, the grant date fair value of RSUs granted was $6.8 million, $5.9 million and $9.3 million, respectively.

RSUs fair value at vested date - The fair value of the RSUs that vested during 2018, 2017 and 2016 was $11.0 million, $5.5 million and $2.4 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 2018, 2017 and 2016 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, 2018, there were 128,980shares 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:

	2018		2017		2016	
	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	246,528	$ 2.27	161,296	$ 3.47	78,230	$ 8.95
Granted	41,544	6.74	147,372	1.90	126,128	2.22
Vested	(106,240)	2.64	(62,140)	4.51	(43,062)	9.75
Nonvested, end of period	181,832	$ 3.08	246,528	$ 2.27	161,296	$ 3.47

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2018 are expected to vest as follows:

	Restricted Shares
2019	105,012
2020	62,972
2021	13,848
Total	181,832

Restricted stock fair value at grant date - The grant date fair value of restricted stock granted during 2018, 2017 and 2016 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 2018, 2017 and 2016 was $0.7 million, $0.1 million and $0.1 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 and the related tax benefit is as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Share-based compensation expense from:			
Restricted stock units	$ 3,260	$ 7,785	$ 10,640
Restricted stock	280	280	373
Total	$ 3,540	$ 8,065	$ 11,013
Share-based compensation tax benefit:			
Tax benefit computed at the statutory rate	$ 743	$ 1,694	$ 3,855

As of December 31, 2018, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $6.4 million and $0.4 million, respectively. Unrecognized compensation expense will be recognized through November 2020 for our RSUs and April 2021 for our Restricted Shares.

Cash-based Awards

In addition to share-based compensation, cash-based awards were granted under the Plan to substantially all eligible employees in 2018, 2017 and 2016. The cash-based awards, which are 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. Expense is recognized over the service period once the business criteria, individual performance criteria and financial condition are met.

- For the 2018 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 2018 for a portion of the 2018 cash-based awards. Payments are expected to be made in March 2019 and are subject to all the terms of the 2018 Annual Incentive Award Agreement.

- For the 2017 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 2017 and in the first quarter of 2018 for the 2017 cash-based awards. Payments were made in March 2018.

- For the 2016 cash-based awards, the financial condition requirement of Adjusted EBITDA less reported Interest Expense Incurred exceeding $300 million over four consecutive quarters was not achieved by December 31, 2018; therefore no expense was recognized during 2018, 2017 or 2016.

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,		
	2018	2017	2016
Share-based compensation included in:			
General and administrative	$ 3,540	$ 8,065	$ 11,013
Cash-based incentive compensation included in:			
Lease operating expense	3,596	2,101	—
General and administrative	9,586	5,032	—
Total charged to operating income	$ 16,722	$ 15,198	$ 11,013

12. Employee Benefit Plan

We maintain a defined contribution benefit plan (the "401(k) Plan") in compliance with Section 401(k) of the Internal Revenue Code ("IRC"), which covers those employees who meet the 401(k) Plan's eligibility requirements. From March 5, 2016 to March 1, 2017, the Company suspended matching contributions. During the time periods where matching occurred, the Company's matching contribution was 100% of each participant's contribution up to a maximum of 6% of the participant's eligible compensation, subject to limitations imposed by the IRC. The 401(k) Plan provides 100% vesting in Company match contributions on a pro rata basis over five years of service (20% per year). Our expenses relating to the 401(k) Plan were $2.0 million, $1.4 million and $0.4 million for 2018, 2017 and 2016, respectively.

13. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2018	2017	2016
Current	$ 35	$ (12,786)	$ (71,768)
Deferred	500	217	28,392
Total income tax expense (benefit)	$ 535	$ (12,569)	$ (43,376)

Effective Tax Rate Reconciliation

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

	Year Ended December 31,					
	2018		2017		2016	
Income tax expense (benefit) at the federal statutory rate	$ 52,366	21.0 %	$ 23,490	35.0 %	$ (102,339)	35.0 %
Compensation adjustments	457	0.2	664	1.0	4,920	(1.7)
State income taxes	560	0.2	63	0.1	(755)	0.2
Debt restructuring cost	—	—	18	—	1,463	(0.5)
Impact of U.S. tax reform	487	0.2	105,933	157.8	—	—
Gain on exchange of debt	—	—	(24,981)	(37.2)	—	—
Valuation allowance	(53,980)	(21.7)	(118,643)	(176.8)	52,915	(18.1)
Other	645	0.3	887	1.4	420	(0.1)
Total income tax expense (benefit)	$ 535	0.2 %	$ (12,569)	(18.7 %)	$ (43,376)	14.8 %

Our effective tax rate for the years 2018, 2017 and 2016 differed from the applicable federal statutory rate of 21.0% for 2018 and 35.0% for 2017 and 2016 primarily due to recording and adjusting a valuation allowance for our deferred tax assets, which is discussed below.

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, 2018	December 31, 2017
Deferred tax liabilities:		
Derivatives	$ 11,139	$ —
Investment in non-consolidated entity	6,875	—
Other	812	695
Total deferred tax liabilities	18,826	695
Deferred tax assets:		
Property and equipment	3,934	18,234
Asset retirement obligations	65,811	63,755
Federal net operating losses	10,039	18,988
State net operating losses	7,133	7,126
Interest expense carryover	41,814	—
Exchange transaction	—	55,807
Share-based compensation	583	1,335
Valuation allowance	(117,764)	(171,547)
Other	7,091	6,805
Total deferred tax assets	18,641	503
Net deferred tax liabilities	$ (185)	$ (192)

During 2018, we received refunds of $11.1 million and made income tax payments of $0.1 million. During 2017, we received refunds of $11.9 million and made income tax payments of $0.2 million. During 2016, we received $7.8 million of refunds and made income tax payments of $0.3 million. The refunds received in 2018, 2017 and 2016 were primarily due to net operating loss ("NOL") carryback claims made pursuant to IRC Section 172 (f) (related to rules regarding "specified liability losses").

Income Taxes Receivable

As of December 31, 2018, we have current income taxes receivable of $54.1 million whichprimarily relates to our NOL carryback claims for the years 2012, 2013 and 2014 that were carried back to prior years. These carryback claims were made pursuant to IRC Section 172 (f), which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. The refund claims require a review by the Congressional Joint Committee on Taxation.

Net Operating Loss, Interest and Tax Credit Carryovers

The table below presents the details of our net operating loss and tax credit carryovers as of December 31, 2018 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 47,804	N/A
State net operating losses	117,835	2025-2036
Interest limitation carryover	197,049	N/A

Valuation Allowance

During 2018 and 2017, we recorded a decrease in the valuation allowance of $53.8 million and $118.6 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. As of December 31, 2018 and 2017, we had a valuation allowance related to our federal and state deferred tax asset.

On December 22, 2017, the Tax Cuts and Jobs Act ("TCJA") was enacted into law and we applied the guidance in Staff Accounting Bulletin No. 118 when accounting for the enactment-date effects of the TCJA in 2018 and 2017. As a result of the enactment of the TCJA, our net deferred tax assets and its respective valuation allowance were provisionally adjusted downwards by $105.9 million as of December 31, 2017. Our Consolidated Statement of Income, Consolidated Balance Sheet and Consolidated Statement of Cash Flow for the year 2017 were not materially impacted as a result of the provisional re-measurement of our net deferred tax assets and its related valuation allowance. At December 31, 2017, we had not completed our accounting for all of the enactment-date income tax effects of the TCJA under Accounting Standards Codification Topic 740, *Income Taxes*, for the measurement of deferred tax assets and liabilities. As of December 31, 2018, we completed our accounting for all of the enactment-date income tax effects of the TCJA and during 2018 we recognized an adjustment of $0.5 million to the provisional amounts recorded at December 31, 2017.

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. Pending settlement of net operating loss carryback claims would require a change in our unrecognized tax benefits and materially impact on our effective tax rate if recognized. If recognized, our estimate of recognized tax benefits would be in the range of $11.5 million to $12.0 million.

Balances in the uncertain tax positions are as follows (in thousands):

	December 31,	
	2018	2017
Balance, beginning and end of period	$ 9,482	$ 9,482

We recognize interest and penalties related to uncertain tax positions in income tax expense. For 2018, 2017 and 2016, the amounts recognized in income tax expense were immaterial.

Years open to examination

The tax years from 2013 through 2018 remain open to examination by the tax jurisdictions to which we are subject.

14. Earnings (Loss) 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 (loss) per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$ 248,827	$ 79,682	$ (249,020)
Less portion allocated to nonvested shares	9,727	3,244	—
Net income (loss) allocated to common shares	$ 239,100	$ 76,438	$ (249,020)
Weighted average common shares outstanding	139,002	137,617	95,644
Basic and diluted earnings (loss) per common share	$ 1.72	$ 0.56	$ (2.60)
Shares excluded due to being anti-dilutive (weighted-average)	—	—	5,269

15. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2018	2017	2016
Supplemental cash items:			
Cash paid for interest, net of interest capitalized of $0 in 2018, $0 in 2017 and $520 in 2016 (1)	$ 61,501	$ 65,873	$ 96,501
Cash paid for income taxes	138	185	310
Cash refunds received for income taxes	11,126	11,906	7,796
Cash paid for share-based compensation (2)	1,130	874	—
Cash received for interest income	2,385	315	7,889
Non-cash investing activities:			
Accruals of property and equipment	18,575	33,003	9,129
ARO - additions, dispositions and revisions, net	19,877	21,245	10,865
Non-cash financing activities:			
Exchange transaction – non-cash securities issued:			
11.00% 1.5 Lien Term Loan - interest payable	—	—	23,823
9.00%/10.75% Second Lien PIK Toggle Notes – carrying value	—	—	223,905
8.50%/10.00% Third Lien PIK Toggle Notes – carrying value	—	—	213,446
Common stock issued - fair value at issuance date	—	—	106,366
Exchange transaction – non-cash securities exchanged:			
8.50% Unsecured Senior Notes – carrying value	—	—	(712,967)

(1) During 2018, 2017 and 2016, cash paid for interest included amounts related to the debt 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.

(2) During 2018 and 2017, 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 stock. During 2016, only common shares were used to settle vested RSUs and Restrict stock.

16. Commitments

We have operating lease agreements for office space. The lease for our office space terminates in December 2022. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2018 are as follows: 2019–$1.5 million; 2020–$1.6 million; 2021–$1.6 million; 2022–$1.6 million and thereafter–$0.0 million. Total rent expense was approximately $3.4 million, $3.0 million and $3.2 million during 2018, 2017 and 2016, respectively.

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, 2018, we had surety bonds related to the agreement with Total E&P totaling $88.5 million and had no amounts in escrow. The threshold is $91.0 million for 2019 and 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, 2018, neither party had requested a re-appraisal to be made. The current security requirement of $64.0 million, which we have met and could be increased up to $94.0 million depending on certain conditions and circumstances.

During 2018, 2017 and 2016, 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 $5.9 million, $5.7 million and $4.3 million during 2018, 2017 and 2016, 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: 2019–$4.5 million; 2020–$4.2 million; 2021–$3.9 million; 2022–$3.9 million; 2023 - $3.8 million and thereafter–$33.6 million. Future surety bond costs may change due to a number of factors, including changes and interpretations of regulations by the BOEM regulations.

As of December 31, 2018, we had $6.9 million of collateral deposits for certain sureties related to certain surety bonds for appeals submitted to the Interior Board of Land Appeals (the “IBLA”).

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. As of December 31, 2018, the estimated future costs are: 2019–$4.9 million; 2020–$4.0 million; 2021–$2.3 million; 2022–$1.7 million; 2023–$1.2 million; and thereafter–$2.0 million.

We have no drilling rig commitments with a term that exceeded one year as of December 31, 2018 and our drilling rig commitments meet the criteria of an operating lease. Future payments of all drilling rig commitments as of December 31, 2018 were $9.7 million.

17. Related Parties

During 2018, 2017 and 2016, there were certain transactions between us and other companies our CEO either controlled or in which he had an ownership interest. In addition, there were transactions with a company that employs the spouse of our CEO. Our CEO owns an aircraft that the Company used and reimbursed him for such use and for his use pursuant to his employment contract. Airplane services transactions were approximately $1.3 million, $1.2 million and $1.1 million for the years 2018, 2017 and 2016, 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 either equal to or below rates charged by non-related, third-party companies. Payments to such company totaled $21.0 million, $22.8 million and $17.3 million in 2018, 2017 and 2016, respectively. The spouse received commissions partially based on services rendered to W&T which were approximately $0.2 million in 2018 and 2017 and less than $0.2 million for 2016. 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.

18. Contingencies

Apache Lawsuit

On December 15, 2014, Apache filed a lawsuit against the Company 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 $43.2 million, plus $6.3 million in prejudgment interest, attorney's fees and costs assessed in the judgment. We filed an appeal of the trial court judgment in the U.S. Court of Appeals for the Fifth Circuit and provided oral arguments in December 2018. Prior to filing the appeal, in order to stay execution of the judgment, we deposited $49.5 million with the registry of the court in June 2017. Oral arguments occurred on December 4, 2018, but as of the filing date of this Form 10-K, a decision had not been rendered by the U.S. Court of Appeals for the Fifth Circuit.

The deposit of $49.5 million with the registry of the U.S. Court of Appeals for the Fifth Circuit was recorded in *Other assets* (long-term) with a corresponding reduction to *Cash and cash equivalents* on the Consolidated Balance Sheet during 2017. Although we are appealing the decision, based solely on the decision rendered, we recorded $49.5 million in *Other liabilities* (long-term) and $43.2 million in capitalized ARO included in *Oil and natural gas properties and other, net* on the Consolidated Balance Sheet during 2017 and recognized $6.3 million of expense included in *Other (income) expense, net* on the Consolidated Statement of Operations in 2017.

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 the 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; 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 IBLA under the Department of the Interior. 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.

Royalties-In-Kind (“RIK”).

Under a program of the Minerals Management Service (“MMS”) (a Department of Interior 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. Based solely on the District Court’s ruling, we recorded a liability reserve of $2.1 million as of December 31, 2018. We have appealed the ruling to the U.S. Fifth Circuit Court of Appeals, and the government filed a cross-appeal. Briefing and oral arguments (if held) will be completed in 2019.

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 2018, 2017 and 2016, we paid $0.6 million, $1.6 million and $0.5 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 collateral demands from surety bond providers during 2018.

Notices of Proposed Civil Penalty Assessment

During 2018, we did not make any civil penalty payments and during 2017 and 2016, we paid $0.2 million and $0.1 million, respectively, in civil penalties to the Bureau of Safety and Environmental Enforcement ("BSEE") related to Incidents of Noncompliance ("INCs") issued by the BSEE at various offshore locations. We currently have nine open civil penalties issued by the BSEE arising from INCs, which have not been settled as of the filing of this Form 10-K. The INCs underlying these open civil penalties cite alleged non-compliance with various safety-related requirements and procedures occurring at separate offshore locations on various dates ranging from July 2012 to January 2018. The proposed civil penalties for these INCs total $7.7 million. As of December 31, 2018, we have accrued approximately $3.5 million in expenses, which is our best estimate of the final settlement once all appeals have been exhausted. Our position is that the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

Other Claims

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

19. 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, 2018				
Revenues	$ 134,213	$ 149,612	$ 153,459	$ 143,422
Operating income	38,739	48,467	57,147	102,674
Net income (1)	27,640	36,083	46,260	138,844
Basic and diluted earnings per common share	0.19	0.25	0.32	0.96
Year Ended December 31, 2017				
Revenues	$ 124,393	$ 123,323	$ 110,281	$ 129,099
Operating income	28,196	32,888	15,700	33,166
Net income (loss) (1)	24,299	33,315	(1,297)	23,365
Basic and diluted earnings (loss) per common share	0.17	0.23	(0.01)	0.16

(1) During the fourth quarter of 2018, we recorded a gain on debt transactions of $47.1 million and a derivative gain of $59.7 million. During the first quarter of 2017, we recorded a gain on debt transactions of $7.8 million. See Note 2 and Note 9 for additional information.

(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.

20. 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,		
	2018	2017	2016
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 8,169.9	$ 8,102.0	$ 7,932.5
Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities	(7,665.1)	(7,525.0)	(7,387.8)
Net capitalized costs related to producing activities	$ 504.8	$ 577.0	$ 544.7

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,		
	2018	2017	2016
Costs incurred: (1)			
Proved properties acquisitions	$ 24.1	$ 1.1	$ 1.3
Exploration (2) (3)	49.9	62.0	4.8
Development	56.2	92.5	56.9
Unproved properties acquisitions	—	—	0.5
Total costs incurred in oil and gas property acquisition, exploration and development activities	$ 130.2	$ 155.6	$ 63.5

(1) Includes net additions from capitalized ARO of $20.3 million, $21.3 million and $10.8 million during 2018, 2017 and 2016, respectively. These adjustments for ARO are associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.

(2) Includes seismic costs of $1.5 million, $0.5 million and $0.2 million incurred during 2018, 2017 and 2016, respectively.

(3) Includes geological and geophysical costs charged to expense of $5.4 million, $4.2 million and $4.1 million during 2018, 2017 and 2016, 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,		
	2018	2017	2016
Depreciation, depletion, amortization and accretion per Boe	$ 11.24	$ 10.68	$ 13.77

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 approximately 13% of our proved developed non-producing reserves as of December 31, 2018 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, 2018. 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 Unites 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*".

				Total Energy Equivalent Reserves (1)	
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Natural Gas Equivalent (Bcfe)
Proved reserves as of Dec. 31, 2015	35.5	6.6	205.4	76.4	458.1
Revisions of previous estimates (2)	4.6	3.1	32.1	13.0	78.1
Production	(7.2)	(1.5)	(39.7)	(15.4)	(92.2)
Proved reserves as of Dec. 31, 2016	32.9	8.2	197.8	74.0	444.0
Revisions of previous estimates (3)	4.5	0.7	25.8	9.6	57.4
Extensions and discoveries (4)	4.1	0.3	5.4	5.2	31.3
Production	(7.1)	(1.4)	(36.8)	(14.6)	(87.4)
Proved reserves as of Dec. 31, 2017	34.4	7.8	192.2	74.2	445.3
Revisions of previous estimates (5)	11.6	2.8	40.4	21.1	126.7
Extensions and discoveries (6)	0.5	0.3	7.7	2.1	12.6
Purchase of minerals in place (7)	1.5	0.4	9.4	3.4	20.7
Sales of minerals in place (8)	(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
Year-end proved developed reserves:					
2018	31.5	7.8	166.8	67.0	402.2
2017	26.1	7.2	173.5	62.2	373.3
2016	26.6	7.6	183.1	64.7	388.2
Year-end proved undeveloped reserves:					
2018 (9)	7.6	2.0	43.7	17.0	101.9
2017	8.3	0.6	18.7	12.0	72.0
2016	6.3	0.6	14.7	9.3	55.8

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 of 14.2 MMBoe, which included upward revisions of 3.8 MMBoe at our Virgo field, 1.5 MMBoe at our Fairway field, 1.3 MMBoe at our Mississippi Canyon 782 (Dantzler) field, and 1.2 MMBoe at our Main Pass 108 field. Partially offsetting were decreases for price revisions of 1.2 MMBoe.

(3) Primarily related to upward revisions of 6.2 MMBoe, which included upwards revisions of 1.1 MMBoe at our Mississippi Canyon 698 (Big Bend) field, 1.0 MMBoe at our Fairway field, 0.8 MMBoe at our Ewing Bank 910 field and 0.8 MMBoe at our Viosca Knoll 783 (Tahoe/SE Tahoe) field. Additionally, increases of 3.4 MMBoe were due to price revisions.

(4) Primarily related to extensions and discoveries at our Ship Shoal 349 (Mahogany) field of 3.5 MMBoe and at our Main Pass 286 field of 1.5 MMBoe.

(5) Primarily related to upward revisions of 13.8 MMBoe at our Mahogany field and of 5.4 MMBoe at our Ship Shoal 028 field. Additionally, increases of 2.3 MMBoe were due to price revisions.

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

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

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

(9) We believe that we will be able to develop all but 1.8 MMBoe (approximately 11%) of the total of 17.0 MMBoe reserves classified as proved undeveloped ("PUDs") at December 31, 2018, within five years from the date such reserves were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field (Matterhorn) and 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 in each field, will be delayed until an existing well is depleted and available to sidetrack. Based on the latest reserve report, these PUD locations are expected to be developed in 2021 and 2022, respectively.

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,			
	2018	2017	2016	2015
Oil - per barrel	$ 65.21	$ 46.58	$ 36.28	$ 46.94
NGLs per barrel	29.73	22.65	16.82	17.60
Natural gas per Mcf	3.13	2.86	2.47	2.50

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 2019 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,		
	2018	2017	2016
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 3,500.9	$ 2,328.8	$ 1,818.4
Future costs:			
Production	(958.5)	(813.8)	(691.5)
Development	(272.4)	(157.4)	(141.1)
Dismantlement and abandonment	(355.9)	(361.9)	(427.7)
Income taxes (1)	(293.9)	(74.8)	—
Future net cash inflows before 10% discount	1,620.2	920.9	558.1
10% annual discount factor	(553.2)	(180.3)	(79.8)
Total	$ 1,067.0	$ 740.6	$ 478.3

(1) No future income taxes were estimated for 2016 as our tax position had sufficient tax basis to offset estimated future taxes. State income taxes were disregarded due to immateriality.

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,		
	2018	2017	2016
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 740.6	$ 478.3	$ 613.9
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(398.1)	(315.3)	(218.6)
Net changes in price, net of future production costs	571.5	288.0	(275.2)
Extensions and discoveries, net of future production and development costs	53.6	119.3	—
Changes in estimated future development costs	(114.7)	(38.9)	(32.5)
Previously estimated development costs incurred	48.4	102.8	114.5
Revisions of quantity estimates	307.6	106.4	190.1
Accretion of discount	50.5	30.2	52.6
Net change in income taxes	(133.4)	(54.7)	—
Purchases of reserves in-place	27.8	—	—
Sales of reserves in-place	(54.1)	—	—
Changes in production rates due to timing and other	(32.7)	24.5	33.5
Net increase (decrease) in standardized measure	326.4	262.3	(135.6)
Standardized measure, end of year	$ 1,067.0	$ 740.6	$ 478.3

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, 2018 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, 2018, 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, 2018, 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, 2018 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 June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.3	First Supplemental Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.4	Form of 8.50% Senior Notes due 2019 (Incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K, filed June 15, 2011 (File No. 001-32414))
4.5	First Supplemental Indenture, dated as of September 7, 2016, by and among W&T Offshore, Inc., the Guarantors named therein 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 September 13, 2016 (File No. 001-32414))

Exhibit Number	Description
4.6	9.00% / 10.75% Senior Second Lien PIK Toggle Notes due 2020 Indenture, dated as of September 7, 2016, by and among W&T Offshore, Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.7	Form of 9.00% / 10.75% Senior Second Lien PIK Toggle Notes due 2020 (included in Exhibit 4.6) (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.8	8.50% / 10.00% Senior Third Lien PIK Toggle Notes due 2021 Indenture, dated as of September 7, 2016, by and among W&T Offshore, Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.8 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.9	Form of 8.50% / 10.00% Senior Third Lien PIK Toggle Notes due 2021 (included in Exhibit 4.4) (Incorporated by reference to Exhibit 4.4 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.10	Registration Rights Agreement, dated as of September 7, 2016, by and among W&T Offshore, Inc. and the initial holders named therein (Incorporated by reference to Exhibit 4.6 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.11	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))
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*	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))
10.3*	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010 (File No. 001-32414))
10.4*	First Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013 (File No. 001-32414))
10.5*	Second Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013 (File No. 001-32414))
10.6*	Third Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2016 (File No. 001-32414))

Exhibit Number	Description
10.7*	Fourth Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2017 (File No. 001-32414))
10.8*	Employment Agreement between W&T Offshore, Inc. and Tracy W. Krohn dated as of November 1, 2010 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on November 5, 2010 (File No. 001-32414))
10.9*	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))
10.10	Fifth Amended and Restated Credit Agreement, dated as of November 8, 2013, 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 November 13, 2013 (File No. 001-32414))
10.11	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 23, 2015, 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 April 27, 2015 (File No. 001-32414))
10.12	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of May 8, 2015, 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 May 14, 2015 (File No. 001-32414))
10.13	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 30, 2015, 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 November 5, 2015 (File No. 001-32414))
10.14	Fourth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of July 28, 2016, 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 August 3, 2016 (File No. 001-32414))
10.15	Fifth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of August 25, 2016, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as administrative 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 August 31, 2016 (File No. 001-32414))
10.16	$300,000,000 Term Loan Agreement, dated May 11, 2015, by and among W&T Offshore, Inc., Morgan Stanley Senior Funding, Inc., as administrative agent and collateral trustee, and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.17	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))

Exhibit Number	Description
10.18	Form of Support Agreement, effective July 25, 2016, by and among W&T Offshore, Inc. and certain Supporting Noteholders (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 25, 2016 (File No. 001-32414))
10.19	Form of Amendment to Support Agreement by and among the Company and the Supporting Noteholders party thereto (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 16, 2016 (File No. 001-32414))
10.20	1.5 Lien Term Loan Credit Agreement, dated as of September 7, 2016, by and among W&T Offshore, Inc., Cortland Capital Market Services LLC, as Administrative Agent and 1.5 Lien Collateral Agent, and the various lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.21	Priority Confirmation Joinder, dated as of September 7, 2016, by and between Toronto Dominion (Texas) LLC, as Priority Lien Agent, Cortland Capital Market Services LLC, as Administrative Agent and 1.5 Lien Collateral Agent, and Morgan Stanley Senior Funding, Inc., as Second Lien Collateral Trustee (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.22	Priority Confirmation Joinder, dated as of September 7, 2016, by and between Toronto Dominion (Texas) LLC, as Priority Lien Agent, Wilmington Trust, National Association, as Second Lien Trustee, and Morgan Stanley Senior Funding, Inc., as Second Lien Collateral Trustee (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.23	Priority Confirmation Joinder, dated as of September 7, 2016, by and between Toronto Dominion (Texas) LLC, as Priority Lien Agent, Morgan Stanley Senior Funding, Inc., as Second Lien Collateral Trustee, and Wilmington Trust, National Association, as Third Lien Trustee and Third Lien Collateral Trustee (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.24	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))
10.25	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))

Exhibit Number	Description
10.26	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))
10.27	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))
10.28*	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))
10.29*	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))
10.30*	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))
10.31*	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))
14.1	W&T Offshore, Inc. Code of Business Conduct and Ethics (as amended). (Incorporated by reference to Exhibit 14.1 of the Company's Current Report on Form 8-K, filed November 17, 2005)
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**	XBRL Instance Document.
101.SCH**	XBRL Schema Document.
101.CAL**	XBRL Calculation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document.
101.LAB**	XBRL Label Linkbase Document.

Exhibit Number	Description
101.PRE**	XBRL Presentation Linkbase Document.

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

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 are used in this report.

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.

BOEMRE. Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service), was the federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf. The BOEMRE was split into three separate entities: the Office of Natural Resources Revenue; the Bureau of Ocean Energy Management; and the Bureau of Safety and Environmental 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 or well. 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.

Non-productive well. A well that is found not to have economically producible hydrocarbons.

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.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

PV-10 value. 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.

Supra-salt. A geological layer lying above 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.

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 February 28, 2019.

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 February 28, 2019.

/s/ Tracy W. Krohn **Tracy W. Krohn**	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)
/s/ Janet Yang **Janet Yang**	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ Virginia Boulet **Virginia Boulet**	Director
/s/ Stuart B. Katz **Stuart B. Katz**	Director
/s/ S. James Nelson, Jr **S. James Nelson, Jr.**	Director
/s/ B. Frank Stanley **B. Frank Stanley**	Director

Exhibit 21.1

SUBSIDIARIES OF W&T OFFSHORE, INC.

The subsidiaries of W&T Offshore, Inc. are listed below.

Name	State of Organization	Percent Owned
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;

of our reports dated February 28, 2019, 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, 2018.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2019

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 February 28, 2019, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated January 29, 2019, and entitled "Estimate 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, 2018," and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2014, 2015, 2016 and 2017. We further consent to the incorporation by reference of information contained in our reports dated January 24, 2018 in the Registration Statements (Form S-3 Nos. 333-224410 and our reports dated February 2, 2016 in the Registration Statements (Form S-3 No. 333-214168) of W&T Offshore, Inc. and in the related Prospectuses and the Registration Statements (Form S-8 Nos. 333-219747, 333-211654 and 333-188584) pertaining to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, as amended and the Registration Statement (Form S-8 Nos. 333-126252) pertaining to the W&T Offshore, Inc. 2004 Directors Compensation Plan and the Registration Statements (Form S-8 Nos. 333-159005 and 333-126251) pertaining to the W&T Offshore, Inc. Long-Term Incentive Compensation Plan, as amended . We also consent to W&T'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
February 28, 2019

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; and
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: February 28, 2019

/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; and

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: February 28, 2019

/s/ JANET YANG

Janet Yang
Executive Vice President, Chief Financial Officer
And Chief Accounting Officer
(Principal Financial 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, 2018 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: February 28, 2019	/s/ Tracy W. Krohn
	Tracy W. Krohn Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)
Date: February 28, 2019	/s/ JANET YANG
	Janet Yang Executive Vice President, Chief Financial Officer And Chief Accounting Officer (Principal Financial Officer)

January 29, 2019 Exhibit 99.1

Mr. Matthew W. McFarland
W&T Offshore, Inc.
Nine Greenway Plaza, Suite 300
Houston, Texas 77046

Dear Mr. McFarland:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2018, 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 (Joint Venture) using the proportional consolidation method. W&T entered into the Joint Venture on February 23, 2018. For the properties in which the Joint Venture has an interest, W&T is obligated to act under the terms as a reasonably prudent operator by disregarding the existence of the Joint Venture's interests as disproportionate burdens affecting such properties. Therefore, the economic viability of these properties has been evaluated based on economic limits associated with the combined total of the W&T direct interest and the Joint Venture interest. 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 Joint Venture.

We estimate the net reserves and future net revenue to the W&T proportional consolidation interest in these properties, as of December 31, 2018, to be:

	Net Reserves			Future Net Revenue(1) (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	25,366.6	6,288.2	133,346.6	1,477,456.3	1,061,836.4
Proved Developed Non-Producing	6,082.2	1,489.6	33,470.3	375,516.9	165,323.2
Proved Undeveloped	7,651.8	2,050.5	43,698.4	417,039.0	212,684.0
Total Proved	39,100.6	9,828.2	210,515.3	2,270,012.2	1,439,843.6

Totals may not add because of rounding.

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

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. Estimates of proved undeveloped reserves have been included for two 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 operators' 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 2018 through December 2018. For oil and NGL volumes, the average West Texas Intermediate spot price of $65.56 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.100 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $65.21 per barrel of oil, $29.73 per barrel of NGL, and $3.131 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 exa mine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the W&T interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on W&T receiving its net revenue interest share of estimated future gross production after field usage and shrinkage.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by W&T, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, petrophysical data, seismic data, well test data, production data, bottomhole pressure data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for behind-pipe zones, non-producing zones, and undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from W&T, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. 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

By: /s/ Ruurdjan (Rudi) de Zoeten

Ruurdjan (Rudi) de Zoeten, P.G. 3179
Vice President

Date Signed: January 29, 2019 Date Signed: January 29, 2019

GSC:ARS

DEFINITIONS OF OIL AND GAS RESERVES

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

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.410(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

> *Supplemental definitions from the 2018 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

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

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

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

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

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

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

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

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

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

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

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

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

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

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

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

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

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

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

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

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

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

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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

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

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

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

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

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

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