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, 2017

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 and posted on its corporate website, if any, every interactive data file required to be submitted and posted 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 (Do not check if a smaller reporting company)	☐	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 $182,243,000 based on the closing sale price of $1.96 per share as reported by the New York Stock Exchange on June 30, 2017.

The number of shares of the registrant's common stock outstanding on February 28, 2018 was 139,091,289.

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 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 Annual Report on 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 Annual Report on 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 49 offshore fields in federal and state waters (47 producing and two fields capable of producing). We currently have under lease approximately 700,000 gross acres (370,000 net acres) spanning across the Outer Continental Shelf ("OCS") off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 470,000 gross acres on the conventional shelf and approximately 230,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in approximately 135 offshore structures, 87 of which are located in fields that 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.

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 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. During 2017 and 2016, a portion of our production was from the deepwater fields, Big Bend and Dantzler, which commenced production in late 2015. The reserves of both of these are comprised of over 75% oil and natural gas liquids ("NGLs") on a Boe basis. As of December 31, 2017, the Big Bend field was in our top ten fields based on reserves, net to our interest, on a Boe basis.

In managing our business, we are focused on optimizing production and growing 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 our commodities produced (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 impact our cash flows and margins. During 2017, commodity prices improved from the lower price levels experienced during 2016 and 2015, but were nonetheless below the levels realized in years prior to 2015. Our margins in 2017 have improved from 2016 and 2015 levels, and are approaching the margin levels achieved prior to 2015. Although we have historically grown our reserves and production through both acquisitions and our drilling programs, for the last three years we have focused on increasing reserves and production through drilling and through projects to optimize production from existing wells. While our production decreased 5.2% in 2017 from the prior year, our reserves increased more than production and resulted in a net increase in reserves year-over-year. The increase in proved reserves is a result of drilling, recompletion and workover effects, and improved commodity prices. During 2017, we drilled five wells on the continental shelf, four of which were successful and began producing during 2017.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum consultants, our total proved reserves at December 31, 2017 were 74.2 million barrels of oil equivalent ("MMBoe") or 445.3 billion cubic feet of gas equivalent ("Bcfe") compared to 74.0 MMBoe as of December 31, 2016. Approximately 74% of our proved reserves as of December 31, 2017 were classified as proved developed producing, 10% as proved developed non-producing and 16% as proved undeveloped. Classified by product, our proved reserves at December 31, 2017 were 46% crude oil, 11% NGLs and 43% natural gas. These percentages were determined using the 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 $992.9 million before consideration of cash outflows related to asset retirement obligations ("ARO"). Our PV-10 after considering future cash outflows related to ARO was $800.7 million, and our standardized measure of discounted future cash flows was $740.6 million as of December 31, 2017. Neither PV-10 nor PV-10 after ARO is a financial measure defined under generally accepted accounting principles ("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.

Under current commodity pricing conditions, we expect to continue to focus on conserving capital and maintaining liquidity. We expect our 2018 production to be lower compared to 2017 before considering any potential acquisition opportunities. Factors such as drilling results, time required to bring successful wells to completion, natural production declines, unplanned downtime and well performance could lead to results different from our production expectations for 2018. Our capital expenditure budget for 2018 of approximately $130 million is composed of select lower-risk, high-return, oil-focused projects combined with higher-risk, higher return, oil-focused projects that, assuming success, would be placed on production fairly quickly.

To provide additional financial flexibility, as we have previously reported, throughout 2017 and now into 2018 we have been working to establish a drilling joint venture with private investors. We are in final stages of establishing a drilling joint venture to be formed with private investors that will allow us to drill and exploit assets on a promoted basis and with reduced capital outlay. We have completed negotiations with an initial group of investors, the terms of which are subject to funding at an initial closing expected to occur by mid-March. It is expected that entities owned and controlled by Tracy W. Krohn, Chairman and Chief Executive Officer of the Company, and his family will invest on the same terms as are negotiated with the unaffiliated investors to acquire an approximate 4% interest in the drilling joint venture. More investors may join the joint venture before or after the initial closing. If completed, this joint venture arrangement should reduce cash commitments for capital expenditures depending on the level of outside investor participation. We believe other arrangements on a promoted basis are available in the current market environment. We believe financing arrangements exist for the right acquisition opportunity, although these financing arrangements may be structured differently than past arrangements.

We also expect to reduce or extend the maturities of a significant amount of our existing indebtedness within the next 12 months assuming reasonably stable market conditions to provide greater financial flexibility. Our 2018 plans include spending $24 million for ARO, compared to $72 million spent on ARO in 2017. We continue to closely monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2018 plans.

Our exploration efforts have historically been in areas in reasonably close proximity to known proved reserves, but starting in 2012, some of our exploration projects were higher risk deepwater projects with potentially higher returns than our previous risk/reward profile. 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 2017, we did not drill or participate in any deepwater projects, and in 2016, we participated in one deepwater project. Certain risks are inherent in our business specifically and in the oil and natural gas industry generally, any one of which can negatively impact our rate of return on invested capital if it occurs. When projects are extremely capital intensive and involve substantial risk, we often seek participants to share the risk.

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.

Business Strategy

Our business strategy is to acquire, explore and develop oil and natural gas reserves on the OCS, the area of our historical success and technical expertise, which we believe will yield desirable rates of return commensurate with our perception of risks. We believe attractive drilling and acquisition opportunities will continue to become available in the Gulf of Mexico as the major integrated oil companies and other large independent oil and gas exploration and production companies continue to divest properties to focus on larger and more capital-intensive projects that better match their long-term strategic goals. Also, we expect opportunities will arise as producers seek to divest their properties for short-term cash flow needs. Our plans for the short-term include operating within cash flow, maintaining liquidity, meeting our financial obligations, establishing a drilling joint venture to provide drilling capital on a promoted basis (as discussed above) and pursuing acquisitions meeting our criteria.

We believe a portion of our Gulf of Mexico acreage has exploration potential below currently producing zones, including deep shelf reserves at subsurface depths greater than 15,000 feet. Although the cost to drill deep shelf wells is significantly higher than shallower wells, the reserve targets are typically larger, and the use of existing infrastructure, when available, can increase the economic potential of these wells.

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 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 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 2017, approximately 46% of our sales were to Shell Trading (US) Co. and 15% were to Vitol Inc., with no other customer comprising greater than 10% of our 2017 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.

Exchange Transaction in 2016

In September 2016, we consummated a transaction whereby we exchanged approximately $710.2 million principal amount, or 79%, of our 8.500% Senior Notes due 2019 (the "Unsecured Senior Notes") for $301.8 million principal amount of new secured notes and 60.4 million shares of our common stock. In conjunction with the transaction, we closed on a new $75.0 million, 11.00%, 1.5 Lien Term Loan (the "1.5 Lien Term Loan"), and two amendments were made effective under our Fifth Amended and Restated Credit Agreement, as amended (the "Credit Agreement") (collectively, the "Exchange Transaction"). See *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7, and in *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, the new debt instruments and the accounting for the transaction.

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") regulations, pursuant to the Outer Continental Shelf Lands Act ("OCSLA"), 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 statues.

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 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. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with BOEM, BSEE, and other government agency regulations and orders that are subject to interpretation and change. The BOEM and BSEE also regulate 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").

Decommissioning and financial assurance requirements. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In July 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. In December 2016, we received an Order to Provide Additional Security from the BOEM totaling approximately $29.5 million for our sole liability properties (the "December 2016 Order"). However, following the BOEM's action in January 2017 to extend the implementation date of NTL #2016-N01 for a period of six months, the BOEM elected to include sole liability properties as being covered under the extension and thus issued us a letter on February 21, 2017 rescinding the December 2016 Order while the BOEM reviewed its financial assurance program. In June 2017, the BOEM further extended the start date for implementing NTL #2016-N01 indefinitely beyond June 30, 2017. This extension currently remains in effect; however, the BOEM reserved the right to re-issue sole liability orders in the future, including in the event that it determines there is a substantial risk of nonperformance of the interest holder's decommissioning sole 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 December 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. Through December 31, 2017, we have paid $ 2.1 million in additional royalties as a result of this initiative.

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 April 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 that 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 December 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 even criminal penalties or the suspension or cessation of operations in affected areas. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict 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 ("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 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. In addition, 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 may not fall within the RCRA exclusion. Moreover, stricter standards for waste handling, disposal and cleanup may be imposed on the oil and natural gas industry in the future. Additionally, Naturally Occurring Radioactive Materials ("NORM") may contaminate minerals extraction and processing equipment used in the oil and natural gas industry. The waste resulting from such contamination is regulated by federal and state laws. Standards have been developed for: worker protection; treatment, storage, and disposal of 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 under RCRA and state laws. We do not anticipate 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 ("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 October 2015, the EPA issued a final rule under the Clean Air Act lowering the National Ambient Air Quality Standard for ground level ozone from 75 to 70 parts per billion. The EPA published a final rule in November 2017 establishing attainment area designations for certain areas of the US and is expected to issue nonattainment designations for additional areas of the US in the first half of 2018, which areas may include regions where we conduct operations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Moreover, the U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of greenhouse gases ("GHG"). These efforts have included consideration of cap-and-trade programs, carbon taxes, and GHG monitoring and reporting programs.

In the absence of federal GHG limitations, 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 and reconsider the entirety of the 2016 rule but the agency has not yet published a final rule and, as a result, the 2016 rule is currently in effect but future implementation of the 2016 rule is uncertain at this time. 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 addition, in January 2018, the BOEM raised OPA's damages liability cap to $137.7 million. 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 the state. 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 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.

Protected and Endangered 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 Endangered Species Act ("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. We own a non-producing platform in the Gulf of Mexico located in a National Marine Sanctuary. 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. During 2017, we reached an agreement with the various governmental agencies to remove the topside structure on our non-producing platform located in the National Marine Sanctuary and leave the bottom of the platform structure below the water line in place. This bottom portion of the platform structure will remain due to the density and diversity of marine growth attached to and around the structure.

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, 2017, we employed 298 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 Annual Report on 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. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. 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 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 prices increased during 2017 from 2016 and 2015 levels, these past three years of lower prices have substantially decreased our revenues on a per unit basis and reduced the amount of crude oil, NGLs and natural gas that we could produce economically. 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”);
- 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.

The prices of crude oil and NGLs began declining in the second half of 2014 and continued declining until reaching a bottom in the first quarter of 2016, and then slowly rising in 2017. The average price per barrel of West Texas Intermediate ("WTI") crude oil was over $90.00 in 2014, approximately $49.00 in 2015, approximately $43.00 per barrel in 2016 and approximately $50.00 per barrel in 2017. During 2014, the average Henry Hub spot price for natural gas was above $4.00 per MMBtu compared to approximately $2.60 per MMBtu during 2015, approximately $2.50 per MMBtu in 2016 and approximately $3.00 per MMBtu in 2017. This decrease and volatility in prices has impacted all companies throughout the oil and gas industry. Although oil prices have increased from the lows of the first quarter of 2016, margins are still below historical levels. Low prices for crude oil, NGLs and natural gas prices could 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 or may not be extended by our lenders.

Availability of borrowings and letters of credit under the Credit Agreement is determined by establishment of a borrowing base, which is periodically redetermined during the year based on our lenders' view of crude oil, NGLs and natural gas prices and on our proved reserves. During 2017, there were no changes in the borrowing base under the Credit Agreement from year-end 2016, but during 2016, the borrowing base was reduced from $350 million to $150 million. The borrowing base was lowered primarily due to declines in commodity prices and a decrease in proved reserves. The borrowing base could be further reduced in the future as a result of the continued impact of low 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 agreements. 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 further 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.

The Credit Agreement matures on November 8, 2018 and our lenders have indicated that they are unwilling to extend the Credit Agreement given the current maturities of our other debt instruments, including the potential maturity acceleration of two of our debt instruments to February 28, 2019. We may not be able to execute our plans to address this issue, which would cause us to operate without a revolving bank credit facility.

We may be unable to provide the financial assurances if the BOEM submits future demands to cover our decommissioning obligations in the amounts and under the time periods required by the BOEM. If extensions and modifications to the BOEM's demands are needed and cannot be obtained, 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 or provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In July 2016, the BOEM issued the 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, ROWs or RUEs. NTL #2016-N01 became effective in September 2016, but the BOEM has since extended indefinitely the start date for implementation.

In December 2016, we received the December 2016 Order totaling approximately $29.5 million for our sole liability properties. However, following the BOEM's action in January 2017 to extend the implementation date of NTL #2016-N01 for a period of six months, the BOEM elected to include sole liability properties as being covered under the extension and thus issued us a letter on February 21, 2017, rescinding the December 2016 Order, while the BOEM reviewed its financial assurance program. In June 2017, the BOEM further extended the start date for the implementation of NTL #2016-N01 indefinitely beyond June 30, 2017. This extension currently remains in effect; however, the BOEM reserved the right to re-issue sole liability orders in the future, including in the event that it determines there is a substantial risk of nonperformance of the interest holder's decommissioning sole liabilities.

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 or financial assurance obligations. Following completion of its review, the BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the review is completed and the BOEM determines what additional financial assurance may be required by us, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or our non-sole liability properties. The BOEM may reject our proposals and make demands that exceed the Company's capabilities.

If we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, 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 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 additional bonding arrangements we may enter into, we may be required to post collateral at any time, on demand, at the surety's discretion. We have received such demands and have provided collateral to a couple of our existing sureties. If additional collateral is required to support surety bond obligations, this collateral would probably be in the form of cash or letters of credit. Given current commodity prices' effect on our creditworthiness and the willingness of the surety to post bonds without the requisite collateral, we cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for additional bonds.

If we are required to provide collateral, our liquidity position will be negatively impacted and may require us 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 and/or future years. In addition, a reduction in our liquidity may impair our ability to comply with the financial and other restrictive covenants in our indebtedness. Moreover, if we default on our Credit Agreement, then we would need a waiver or amendment from our bank lenders to prevent the acceleration of the outstanding debt under our Credit Agreement. There is no assurance that the bank lenders will waive or amend the Credit Agreement. Realization of any of these factors could have a material adverse effect on our financial condition, results of operations and cash flows. 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.

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, 2017, we had $889.8 million principal amount of indebtedness outstanding, which consists of $189.8 million principal amount of unsecured indebtedness and $700.0 million principal amount of secured indebtedness. Our current availability on our revolving bank credit facility is the full borrowing base of $150.0 million. We did not incur any borrowings on our revolving bank credit facility during 2017. For example, our leverage 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 also pledged as collateral on a subordinate basis under certain other debt agreements. Sustained or lower crude oil, NGLs and natural gas prices in the future will continue to adversely affect our cash flow and could result in further 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. Further 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 restructure or 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 and could lead to a restructuring.

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, 2017, we had $700.0 million principal amount of secured indebtedness outstanding and $189.8 million principal amount of unsecured indebtedness outstanding (which does not include amounts recorded in the carrying value of certain debt instruments for future payment-in-kind (“PIK”) and cash interest payments). The components of our indebtedness are:

- $75.0 million in aggregate principal amount of 1.5 Lien Term Loan;
- $300.0 million in aggregate principal amount of the 9.00% Term Loan, due May 2020 (the “Second Lien Term Loan”);
- $171.8 million of Second Lien PIK Toggle Notes;
- $153.2 million of Third Lien PIK Toggle Notes; and
- $189.8 million in aggregate principal amount of the Unsecured Senior Notes.

If new debt is added to our current debt levels, the related risks that we face could intensify. As of December 31, 2017, the various debt agreements allowed for approximately $200 million of second lien debt and approximately $400 million of third lien debt. 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 revolving bank credit facility 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.

A significant amount of our indebtedness will accelerate if we are not able to extend, renew, refund, defease, discharge, replace or refinance our Unsecured Senior Notes by certain dates under various debt agreements, which would adversely impact our liquidity.

The maturity of the Third Lien PIK Toggle Notes and the 1.5 Lien Term Loan will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes are not extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. The Unsecured Senior Notes mature on June 15, 2019 with a principal balance of $189.8 million. Assuming the PIK option is fully utilized for the Third Lien PIK Toggle Notes, the principal balance would be approximately $164.5 million as of February 28, 2019. For the 1.5 Lien Term Loan, no PIK option is available and the principal of $75.0 million would be unchanged as of February 28, 2019. Thus, a total of $239.5 million may become due on February 28, 2019.

In addition, the lenders under our Credit Agreement, which matures on November 8, 2018, have indicated that they are unwilling to extend the Credit Agreement, and other lenders may be unwilling to extend a replacement revolving credit facility, unless and until the potential maturity acceleration of our Third Lien PIK Toggle Notes and the 1.5 Lien Term Loan to February 28, 2019 is addressed. Each of our Second Lien Term Loan and Second Lien PIK Toggle Notes require us to offer to repay or repurchase the Second Lien Term Loan and Second Lien PIK Toggle Notes, as applicable, at par plus accrued and unpaid interest if, by May 16, 2019, the aggregate outstanding principal amount of Unsecured Senior Notes that have not been repurchased, redeemed, discharged, defeased or called for redemption exceeds $50.0 million.

We may not be able to execute on various financing alternatives under consideration to address these maturity issues, which include having sufficient available cash or net proceeds from replacement financings to redeem the Unsecured Senior Notes, which are currently callable at par, and the 1.5 Lien Term Loan, which is callable after September 7, 2018 at 102.75% of par. In addition, certain amendments under the 1.5 Lien Term Loan and the Credit Agreement will likely be required in the event replacement financing is not utilized. We may not have available funds to make these payments, which may cause us to be in default if we are unable to refinance the Unsecured Senior Notes before February 28, 2019. 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 be on less favorable terms or on terms that are not acceptable to us. 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.

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

Sustained or 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 are currently very 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, 2017, we had $700.0 million principal amount of secured indebtedness outstanding, (which does not include amounts recorded in the carrying value of certain debt instruments for PIK and cash interest payments). If in the future we default on one or more issues or tranches of our secured debt, we cannot assure you 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 $149.7 million as of December 31, 2017, available for borrowing on our revolving bank credit facility, 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 assure you 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 assure you 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.

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 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 2017. If prices fall below 2016 levels, this may cause write-downs during 2018 or in future periods. In addition, lower crude oil, NGLs and natural gas prices may reduce our estimates of the 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 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 16% of our total proved reserves as of December 31, 2017 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. Although we are the operator for all the fields containing our PUDs as of December 31, 2017, in the past, we were not the operator for a portion of our PUDs, which if this were to occur in the future, may put us in a position of not being able to control the timing of development activities. Furthermore, there can be no assurance that all of our PUDs will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

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 50% 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 are currently constrained because of our relatively high leverage and we believe our access to capital markets remains limited at this time. Our capital expenditures in 2017 were below historical levels and we continue to have a low capital expenditure budget for 2018 in order to conserve capital and target projects with a high probability of acceptable returns. 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 recently constrained capital budget may adversely affect our ability to sustain our production at 2017 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 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 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 April 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. Also, in April 2016, the BOEM published a proposed rule that would update existing air emissions requirements relating to offshore oil and natural gas activity on the OCS. The BOEM regulates these air emissions in connection with its review of exploration and development plans, and ROWs and RUEs applications. The proposed rule would bolster existing air emissions requirements by, among other things, requiring the reporting and tracking of the emissions of all pollutants defined by the EPA to affect human health and public welfare. These rules and other potential rulemakings could further restrict offshore air emissions.

In May 2017, the Department of the Interior Secretary Ryan Zinke 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 and the 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. Moreover, Order 3350 directed the BOEM to immediately cease all activities to promulgate the April 2016 proposed rule relating to offshore air quality control. One consequence of this review is that in December 2017, the BSEE published proposed revisions to its regulations regarding offshore drilling safety equipment, which proposal includes 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. The December 2017 proposed rule has not been finalized and there remains substantial uncertainty as to the scope and extent of any revisions to existing oil and gas safety and performance-related regulations and other regulatory initiatives that ultimately will be adopted by the BSEE and the BOEM pursuant to those agencies’ review process.

To the extent that the BOEM and the BSEE do not reduce the stringency of existing oil and gas safety and performance-related regulations and other regulatory initiatives, the regulatory requirements imposed by such existing or future, more stringent regulations or other regulatory initiatives could delay 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 $150.0 million aggregate limit covering all of our properties, subject to a retention (deductible) of $30.0 million. Included within the $150.0 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 2017, 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 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 first quarter of 2017, we entered into commodity derivative contracts, which expired on or before December 31, 2017. As of the filing date of this Form 10-K, we did not have any open commodity derivative positions. 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 8 – 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 and limitations recently imposed on us and our ability to finance such acquisitions may put us at a competitive disadvantage for acquiring properties. These risks are described above in the risk factor entitled: *We may be unable to provide the financial assurances if the BOEM submits future demands to cover our decommissioning obligations in the amounts and under the time periods required by the BOEM. If extensions and modifications to the BOEM’s demands are needed and cannot be obtained, 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.*

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 assure you 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, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs 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 sole 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 ("JOAs") 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 is bankrupt or unable to pay its decommissioning costs. For example, we have in the past received a demand for payment of such 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 be jointly and severally liable 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. 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, net production of approximately 1.7 MMBoe was deferred during 2017 due to Hurricane Nate, pipeline issues and other events. A similar amount was deferred during 2016 due to events outside of our control.

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 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, 2017. 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 21 – 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 rate 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 and in 2017 from Hurricane Nate.

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, 2017, 10 fields, accounting for approximately 0.8 MMBoe (or 6%) of our 2017 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 2017, 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:

- land use restrictions;
- 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, endangered species laws and regulations.

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 and other protected areas or that may affect certain wildlife, including marine mammals; 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 be held strictly liable 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.

Future environmental laws and regulations 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 and endangered species regulations.

The ONNR'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, 2017, we paid $2.1 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, greenhouse gas reporting and tracking programs, and regulations that directly limit greenhouse gas emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented. 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 greenhouse gas emissions on an annual basis from specified large greenhouse gas 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 greenhouse gas, from oil and natural gas operations as described above. Compliance with these rules could result in increased compliance costs on our operations.

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 greenhouse gas emission inventories and/or regional greenhouse gas 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 greenhouse gas emission reduction goal. 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; John D. Gibbons, our Senior Vice President and Chief Financial Officer; Thomas P. Murphy, our Senior Vice President and Chief Operations Officer; and Stephen L. Schroeder, our Senior Vice President and Chief Technical Officer, 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 available to corporations. 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 will have an impact on our taxation and generally take effect for tax years beginning after 2017. 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.

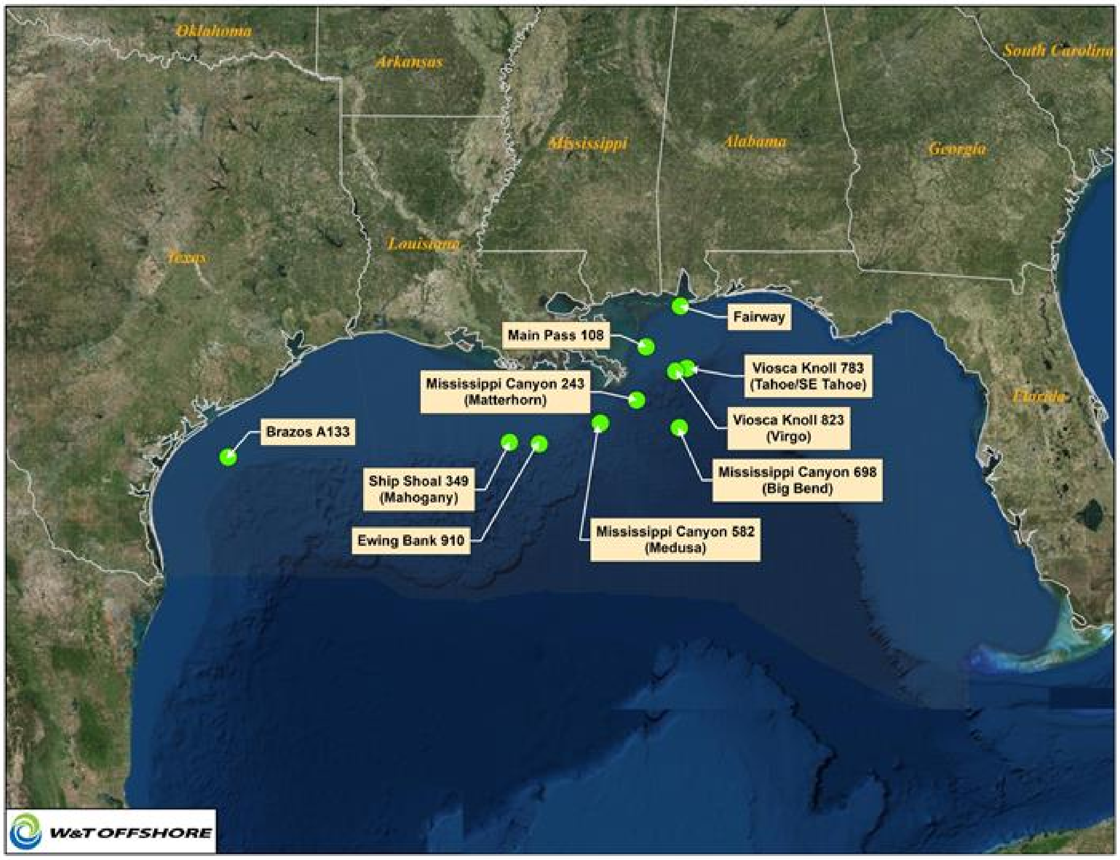
Substantially all of our accounts receivable result from crude oil, NGLs and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected 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. The following map provides the locations of our 10 largest fields as of December 31, 2017, based on quantities of proved reserves on an energy equivalent basis. At December 31, 2017, these fields accounted for approximately 80% of our proved reserves.



The following table provides information for our 10 largest fields determined using quantities of proved net reserves on an energy equivalent basis as of December 31, 2017. 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. 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:

Field Name	Field Category	Percent Oil and NGLs of Proved Reserves (1)	2017 Average Daily Equivalent Sales Rate (Boe/d) (1)	
			Gross	Net
Ship Shoal 349 (Mahogany)	Shelf	82%	8,332	6,943
Fairway	Shelf	25%	5,176	3,882
Miss. Canyon 243 (Matterhorn)	Deepwater	81%	1,613	1,613
Viosca Knoll 783 (Tahoe/SE Tahoe)	Deepwater	29%	4,142	2,816
Viosca Knoll 823 (Virgo)	Deepwater	32%	2,231	1,420
Main Pass 108	Shelf	19%	3,682	2,894
Miss. Canyon 698 (Big Bend)	Deepwater	93%	17,320	2,815
Brazos A133	Shelf	—	2,081	867
Ewing Bank 910	Deepwater	68%	4,513	2,055
Miss. Canyon 582 (Medusa)	Deepwater	92%	4,634	695

(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.

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

Our Fields

On December 31, 2017, we had two fields of major individual 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. 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. Cumulative field production through 2017 is approximately 46.4 MMBoe gross. This field is a sub-salt development with nine productive horizons below salt at depths up to 18,000 feet. As of December 31, 2017, 28 wells have been drilled and 23 were successful. Since acquiring an interest and subsequently taking over as operator, we have directly participated in drilling 14 wells with a 100% success rate. During 2017, one well was completed which had been drilled to target depth during 2016. Three additional wells were drilled during 2017, two of which were completed in 2017 with the third expected to be completed in the first half of 2018. All of the wells drilled under a plan developed in 2010 have been successful. Total proved reserves associated with our interest in this field were 21.6 MMBoe at December 31, 2017, 19.8 MMBoe at December 31, 2016 and 22.3 MMBoe at December 31, 2015.

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,		
	2017	2016	2015
Net Sales:			
Oil (MBbls)	1,896	1,332	2,313
NGLs (MBbls)	163	159	97
Natural gas (MMcf)	2,853	1,871	3,764
Total oil equivalent (MBoe)	2,534	1,802	3,037
Total natural gas equivalents (MMcfe)	15,205	10,812	18,221
Average daily equivalent sales (Boe/day)	6,943	4,924	8,320
Average daily equivalent sales (Mcfe/day)	41,656	29,543	49,922
Average realized sales prices:			
Oil ($/Bbl)	$ 46.64	$ 31.97	$ 42.73
NGLs ($/Bbl)	25.42	17.88	21.27
Natural gas ($/Mcf)	3.16	2.38	2.86
Oil equivalent ($/Boe)	40.08	27.67	36.77
Natural gas equivalent ($/Mcfe)	6.68	4.61	6.13
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 4.30	$ 5.16	$ 3.30
Natural gas equivalent ($/Mcfe)	0.72	0.86	0.55

(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 2017 is approximately 131.8 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, 2017, 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 13.2 MMBoe at December 31, 2017, 13.7 MMBoe at December 31, 2016 and 14.0 MMBoe at December 31, 2015.

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,		
	2017	2016	2015
Net Sales:			
Oil (MBbls)	10	9	10
NGLs (MBbls)	362	400	319
Natural gas (MMcf)	6,270	7,817	8,277
Total oil equivalent (MBoe)	1,417	1,712	1,708
Total natural gas equivalents (MMcfe)	8,501	10,272	10,250
Average daily equivalent sales (Boe/day)	3,882	4,678	4,680
Average daily equivalent sales (Mcfe/day)	23,292	28,065	28,083
Average realized sales prices:			
Oil ($/Bbl)	$ 47.65	$ 41.15	$ 47.22
NGLs ($/Bbl)	21.13	16.72	18.97
Natural gas ($/Mcf)	2.93	2.42	2.60
Oil equivalent ($/Boe)	18.68	17.32	16.40
Natural gas equivalent ($/Mcfe)	3.11	2.89	2.73
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 8.46	$ 7.95	$ 8.96
Natural gas equivalent ($/Mcfe)	1.41	1.32	1.49

(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, 2017, 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):

Mississippi Canyon 243 Field (Matterhorn). 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 2017 is approximately 37.1 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, 2017, 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 2017, production from this field, net to our interest, averaged 775 barrels of crude oil per day, 27 barrels of NGLs per day and 1,956 Mcf of natural gas per day, for total production of 1,128 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 2017 is approximately 101.5 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, 2017, 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 2017, production from this field, net to our interest, averaged 113 barrels of crude oil per day, 645 barrels of NGLs per day and 11,605 Mcf of natural gas per day, for total production of 2,692 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. Cumulative field production through 2017 is approximately 23.7 MMBoe gross. This field is a supra-salt development with 17 productive horizons at depths ranging to 13,335 feet. As of December 31, 2017, 14 wells have been drilled, 10 of which have been successful. During December 2017, production from this field, net to our interest, averaged 224 barrels of crude oil per day, 129 barrels of NGLs per day and 5,368 Mcf of natural gas per day, for total production of 1,248 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 Oil and Gas Corporation ("Kerr-McGee") and we are the operator of this field. Cumulative field production through 2017 is approximately 48.6 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, 2017, 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 2017, production from this field, net to our interest, averaged 317 barrels of crude oil per day, 264 barrels of NGLs per day and 13,189 Mcf of natural gas per day, for total production of 2,779 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 Noble Energy Inc. 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. Cumulative field production through 2017 is approximately 12.4 MMBoe gross. The field is a supra-salt development with two productive horizons at depths ranging from 14,660' to 15,533' total vertical depth. As of December 31, 2017, one well has been drilled, which was successful, with the well beginning production in the fourth quarter of 2015. During December 2017, production from this field, net to our interest, averaged 2,340 barrels of crude oil per day, 62 barrels of NGLs per day and 1,413 Mcf of natural gas per day, for total production of 2,637 Boe per day.

Brazos A-133 Field. Brazos A-133 field is located 85 miles east of Corpus Christi, Texas in 200 feet of water. The field was discovered in 1978 by Cities Service Oil Company with production commencing in the same year. There are five active platforms, three of which are production platforms. Cumulative field production through 2017 is approximately 154.9 MMBoe gross from the Middle Miocene Tex W and Big Hum sections. The bulk of the production is from the Big Hum CM-7 sand, which is a 4-way closure downthrown to the Corsair Fault and bisected by antithetic faults. The top of the CM-7 sand is at a subsea depth of 12,000 feet. Since its discovery, 22 wells have been drilled, 17 of which were successful. We own a 50% working interest, of which 25% was obtained through a transaction with Kerr-McGee in 2006 and an additional 25% was obtained through a transaction with Chevron U.S.A. Inc. in 2015. During December 2017, production from this field, net to our interest, averaged 49 barrels of crude oil per day and 4,426 Mcf of natural gas per day, for total production of 787 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. Two recently successful deep wells are subject to a 50% working interest with Walter Oil and Gas Corporation. A single production platform is located on Block 910. Cumulative field production through 2017 is approximately 17.6 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, 11 wells have been drilled, nine of which were successful. Since acquiring an interest in this field, we have directly participated in drilling three wells with 100% success rate. During December 2017, production from this field, net to our interest, averaged 1,069 barrels of crude oil per day, 225 barrels of NGLs per day and 3,543 Mcf of natural gas per day, for total production of 1,884 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 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 2017 is approximately 82.0 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 2017, production from this field, net to our interest, averaged 565 barrels of crude oil per day, 4 barrels of NGLs per day and 1,593 Mcf of natural gas per day, for total production of 835 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, 2017 are summarized below and the mix by product was 46% oil, 11% NGLs and 43% 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	22.4	6.6	153.1	54.5	326.9	74%	$ 716.8
Proved developed non-producing	3.7	0.6	20.4	7.7	46.4	10%	87.8
Total proved developed	26.1	7.2	173.5	62.2	373.3	84%	804.6
Proved undeveloped	8.3	0.6	18.7	12.0	72.0	16%	188.3
Total proved	34.4	7.8	192.2	74.2	445.3	100%	$ 992.9

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

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2017 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, 2017. 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 $46.58 per barrel for oil, $22.65 per barrel for NGLs and $2.86 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, 2017
Present value of estimated future net revenues (PV-10)	$ 992.9
Present value of estimated ARO, discounted at 10%	(192.2)
PV-10 after ARO	800.7
Future income taxes, discounted at 10%	(60.1)
Standardized measure of discounted future net cash flows	$ 740.6

Changes in Proved Reserves

Our total proved reserves at December 31, 2017 were 74.2 MMBoe compared to 74.0 MMBoe at December 31, 2016, representing an overall increase of 0.2 MMBoe. After accounting for 14.6 MMBoe of 2017 production, total revisions were a positive 14.8 MMBoe. Increases from extensions and discoveries were 5.2 MMBoe, positive technical revisions (including increased well performance) were 6.2 MMBoe and increases due to higher commodity prices were estimated to be 3.4 MMBoe. Due to successful drilling and recompletion projects, our proved developed producing reserves increased from 47.3 MMBoe as of December 31, 2016 to 54.5 MMBoe as of December 31, 2017, after accounting for 2017 production.

See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2017. See *Financial Statements and Supplementary Data– Note 21 – 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, 2017 are calculated based upon SEC mandated 2017 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 2017 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, 2017 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 28 years of oil and gas industry experience and has managed the preparation of public company reserve estimates the last 14 years. He joined the Company in mid-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 Oil & Gas 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 proved undeveloped reserves ("PUDs") were estimated by NSAI, our independent petroleum consultant. Future development costs associated with our PUDs at December 31, 2017 were estimated at $119.5 million.

The following table presents our PUDs by field (in MMBoe):

	December 31,		
	2017	2016	2015
Ship Shoal 349 (Mahogany)	5.8	4.5	4.0
Mississippi Canyon 243 (Matterhorn)	1.8	2.2	2.0
Viosca Knoll 823 (Virgo)	2.4	2.1	—
Ewing Bank 910	0.5	0.5	0.5
Mississippi Canyon 698 (Big Bend)	—	—	0.9
Main Pass 286	1.5	—	—
Total	12.0	9.3	7.4

The following table presents a reconciliation of our PUDs (in MMBoe):

	Year Ended December 31,		
	2017	2016	2015
Proved undeveloped reserves, beginning of year	9.3	7.4	36.7
Reductions:			
Ship Shoal 349 (Mahogany)	(2.3)	(1.9)	—
Mississippi Canyon 243 (Matterhorn)	(0.4)	—	(0.2)
Viosca Knoll 823 (Virgo)	—	—	(2.0)
Mississippi Canyon 698 (Big Bend)	—	(0.9)	(1.0)
Mississippi Canyon 582 (Medusa)	—	—	(0.3)
Mississippi Canyon 782 (Dantzler)	—	—	(4.1)
Spraberry (Yellow Rose)	—	—	(24.9)
Subtotal - reductions	(2.7)	(2.8)	(32.5)
Balance after reductions	6.6	4.6	4.2
Additions:			
Ship Shoal 349 (Mahogany)	3.6	2.4	2.0
Mississippi Canyon 243 (Matterhorn)	—	0.2	0.7
Viosca Knoll 823 (Virgo)	0.3	2.1	—
Ewing Bank 910	—	—	0.5
Main Pass 286	1.5	—	—
Subtotal - additions	5.4	4.7	3.2
Proved undeveloped reserves, end of year	12.0	9.3	7.4

Activity related to PUDs in 2017:

- During 2017, we drilled and converted one PUD location described below, which resulted in 2.3 MMBoe reclassified from PUDs to proved developed reserves ("PDs"). Approximately $17.8 million of capital expenditures were incurred in 2017 related to developing this one PUD location to PD and related to activities in progress at December 31, 2017 to develop another PUD location to PD if drilling results are successful. This development activity in 2017 resulted in reclassification of approximately 25% of the PUDs existing at December 31, 2016 to proved developed status measured on a Boe basis.

- At our Ship Shoal 349 field (Mahogany), we converted one PUD location to PD with the successful drilling and completion of the A-8 BP1 well. Subsequent exploration drilling in the field resulted in the addition of one new extension PUD location that is expected to be completed in the first half of 2018.

- Successful exploratory drilling in Main Pass block 286 resulted in the addition of one PUD location in a new field. Development planning is ongoing with plans to complete the well in late 2018 or early 2019.

- At our Viosca Knoll 823 field (Virgo), a rig has been mobilized to the platform during the first quarter of 2018 and drilling is expected to commence during the first half of 2018.

Activity related to PUDs in 2016:

- During 2016, we drilled and converted one PUD location and 1.9 MMBoe to PDs. Approximately $25.7 million of capital expenditures were incurred related to developing this PUD location to PD. Development activity in 2016 resulted in reclassification of approximately 26% of the PUDs existing at December 31, 2015 to proved developed status.

- At our Ship Shoal 349 field (Mahogany), PUD reserves were added due to drilling the A-18 well to target depth and beginning completion activities. Although the A-18 well was not completed by year-end 2016, the data available from the drilling activity and initial completion activities led to the conversion of the A-18 well from PUD to PD and resulted in the recognition of one additional offsetting PUD location.

- At our Viosca Knoll 823 field (Virgo), PUDs were added as two locations were reclassified from probable to PUD, which we plan on drilling in 2018.

- At our Mississippi Canyon 243 field (Matterhorn), reserves associated with existing PUD locations were added due to performance evaluations of adjacent PDs and economic field life extension resulting from ongoing success in managing and reducing lease operating expenses.

- At our Mississippi Canyon 698 field (Big Bend), updated field performance data demonstrated that all proved reserves could be recovered from the producing SS1 well and that an additional take point previously classified as a PUD was unnecessary. These proved reserve volumes were reclassified from PUD to PDP and the associated future development capital was eliminated.

Activity related to PUDs in 2015:

- During 2015, we completed five offshore wells which affected the conversion of PUDs to PDs and affected additional PUDs to be recognized. Three of the five wells were drilled prior to 2015. Approximately $141.0 million of capital expenditures was incurred related to these five wells during 2015. Activity, divestitures and development assessments in 2015 resulted in reclassification of approximately 88% of the PUDs existing at December 31, 2014.

- At our Spraberry field (Yellow Rose), our interests were divested and we were assigned an ORRI.

- At our Mississippi Canyon 698 field (Big Bend), we completed one well which moved PUDs to PDs.

- At our Viosca Knoll 823 field (Virgo), one well was removed from PUDs as the development timing was beyond the five year limitation and another well was removed from PUDs as it was determined to be uneconomic.

- At our Mississippi Canyon 782 field (Dantzler), we completed two wells which moved PUDs into PDs.

- At our Ship Shoal 349 field (Mahogany), PUD reserves were added based on performance, remapping and technical changes.

- At our Mississippi Canyon 243 field (Matterhorn), PUDs were added due to the assessment related to two wells.

See *Business* under Part I, Item 1, *Our Fields* in Item 2 above and *Financial Statements and Supplementary Data – Note 7 –Divestitures* under Part II, Item 8 in this Form 10-K for additional information.

We believe that we will be able to develop all but 1.8 MMBoe (approximately 15%) of the total 12.0 MMBoe classified as PUDs at December 31, 2017, within five years from the date such reserves were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field (Matterhorn) where the field is being developed using a single floating tension leg platform requiring an extended sequential development plan. The platform cannot support a rig that would allow additional wells to be drilled, but can support a rig to allow sidetracking of wells. Two sidetrack PUD locations in this 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 2023.

Our capital expenditure budget for 2018 is $130 million, which excludes potential acquisitions, and has over 50% allocated for development. Four of the eight wells that comprised our PUD locations as of December 31, 2017 are scheduled to be developed in 2018.

Acreage

The following table summarizes our leasehold at December 31, 2017. Deepwater refers to acreage in over 500 feet of water:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Shelf	414,178	235,345	53,604	38,536	467,782	273,881
Deepwater	147,689	61,219	87,715	36,560	235,404	97,779
Total	561,867	296,564	141,319	75,096	703,186	371,660

Approximately 80% 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, 21,870 net acres (29%) of the total 75,096 net undeveloped acres could expire in 2018, 27,719 net acres (37%) could expire in 2019, 11,912 net acres (16%) could expire in 2020, 5,760 net acres (8%) could expire in 2021, and 7,835 net acres (10%) could expire in 2022 and beyond. In making decisions regarding drilling and operations activity for 2018 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 leaseholds that may expire in 2018, 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 by the acquiring party.

Our net acreage decreased 80,876 net acres (18%) from December 31, 2016 due to sales, lease expirations and relinquishments.

Production

For the years 2017, 2016 and 2015, our net daily production averaged 39,921 Boe, 41,980 Boe and 46,709 Boe, respectively. Production decreased in 2017 from 2016 primarily due to natural production declines, pipeline and platform outages, and tropical storm activity, partially offset by production from four completed wells, which came on-line during various months throughout 2017. 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,		
	2017	2016	2015
Net Sales:			
Oil (MBbls)	7,064	7,201	7,751
NGLs (MBbls)	1,381	1,542	1,604
Oil and NGLs (MBbls)	8,445	8,743	9,355
Natural gas (MMcf)	36,754	39,731	46,163
Total oil equivalent (MBoe)	14,571	15,365	17,049
Total natural gas equivalents (MMcfe)	87,428	92,188	102,294

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 Ship Shoal 349/359 field (Mahogany) and the Fairway Field over the past three fiscal years, which have proved reserves exceeding 15% 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, 2017 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 (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	84	75	60	50	144	125
Non-operated	34	8	28	7	62	15
Total offshore wells	118	83	88	57	206	140

(1) Includes 13 gross (10.0 net) oil wells and six gross (4.9 net) gas wells with multiple completions

Drilling Activity

As presented in the tables below, our drilling activity increased in 2017 as compared to 2016. As the Yellow Rose properties were divested during 2015 and we do not currently have any onshore drilling activities, historical data for onshore drilling was excluded from the table below.

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,		
	2017	2016	2015
Development Wells Completed:			
Gross wells	3.0	—	—
Net wells	3.0	—	—
Exploration Wells Completed:			
Gross wells	1.0	1.0	5.0
Net wells	0.8	0.5	1.2

Our success rates related to our development and exploration wells drilled was 80% in 2017 and 100% in 2016 and 100% in 2015. One exploration well drilled during 2017 was non-commercial, of which we had a 39% working interest.

Recent Drilling Activity

During January 2017, we completed the A-18 offshore development well at the Ship Shoal 349 field (Mahogany). We also drilled and completed two other wells at Mahogany, one of which began production in April 2017 and the other began production in July 2017. The fourth successful well was at the Ship Shoal 300 field and began production in November 2017.

During the first two months of 2018, we mobilized a rig to the Viosca Knoll 823 (Virgo) platform and drilled the Viosca Knoll 823 A-10 ST1 well to target depth. The A-17 well at Mahogany and the #1 well at Main Pass 286 have both been drilled to target depth. Completion operations are in progress for the A-17 well at Mahogany. The Main Pass 286 #1 well was successful and logged pay as a new field discovery. The Main Pass 286 #1 well has been cased and is waiting for development sanction, which is expected during 2018. First production is expected in early 2019.

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 2018 capital expenditure budget at $130 million, which excludes potential acquisitions, and is similar to the level of capital expenditures incurred in 2017. 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 (“MC”) 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. 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.

The dispute relates to Apache's use of drilling rigs instead of a previously contracted intervention vessel for the plugging and abandonment work. We contended that the costs to use the drilling rigs were unnecessary and unreasonable, and that Apache chose to use the rigs without W&T's consent because they otherwise would have been idle at Apache's expense. We believe the use of the rigs was in bad faith, as found by the jury, and that such conduct caused W&T not to comply with the applicable joint operating agreement, particularly since another vessel had been contracted by Apache for the abandonment a year in advance. We had previously paid $24.9 million to Apache as an undisputed amount for the plug and abandonment work.

On October 28, 2016, the jury made the following findings:

1. W&T failed to comply with the contract by failing to pay its proportionate share of the costs to plug and abandon the MC 674 wells.
2. The amount of money to compensate Apache for W&T’s failure to pay its proportionate share of the costs to plug and abandon the MC 674 wells was $43.2 million.
3. The $43.2 million referred to in #2 should be offset by $17.0 million.
4. Apache acted in bad faith thereby causing W&T to not comply with the contract.

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 an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana.

Monetary Sanctions by Government Authorities. (***Notices of Proposed Civil Penalty Assessment***) We currently have four open civil penalties issued by the BSEE arising from Incidents of Noncompliance (“INCs”), which have not been settled as of the filing of this Form 10-K. The INC’s underlying the civil penalties were issued during 2015, with one re-issued during 2016, and relate to four separate offshore locations with occurrence dates ranging from July 2012 to June 2014. The proposed civil penalties for these INCs total $7.3 million. We have accrued approximately $3.3 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. For 2017 and 2016, we paid $0.2 million and $0.1 million, respectively, related to civil penalties issued by the BSEE.

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. In addition, the BOEM considers all owners of record title and/or operating rights interest in an OCS lease to be jointly and severally liable for the satisfaction of the financial assurance requirements and/or decommissioning obligations that have accrued to such owners. Accordingly, we may be required to satisfy financial assurance requirements or decommissioning obligations of a defaulting owner of record title and/or operating rights interest in an OCS lease in which we are (or in some cases were) an owner of record title and/or operating rights interest in the same OCS lease. 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 federally-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 17 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information on this matters described above.

Executive Officers of the Registrant

The following table lists our executive officers:

Name	Age (1)	Position
Tracy W. Krohn	63	Chairman, Chief Executive Officer and President
John D. Gibbons	64	Senior Vice President and Chief Financial Officer
Thomas P. Murphy	55	Senior Vice President and Chief Operations Officer
Stephen L. Schroeder	55	Senior Vice President and Chief Technical Officer
Shahid A. Ghauri	49	Vice President, General Counsel and Secretary

(1) Ages as of February 23, 2018

Tracy W. Krohn has served as Chief Executive Officer since he founded the Company in 1983 and as Chairman since 2004. He also served as President of the Company until September 2008 and again since March 2017. During 1996 to 1997, Mr. Krohn was also Chairman and Chief Executive Officer of Aviara Energy Corporation. Prior to founding the Company, from 1982 to 1983, Mr. Krohn was a senior engineer with Taylor Energy, and he began his career as a petroleum engineer and offshore drilling supervisor with Mobil Oil Corporation.

John D. Gibbons joined the Company in February 2007 as Senior Vice President and Chief Financial Officer. Prior to joining the Company, Mr. Gibbons was Senior Vice President and Chief Financial Officer of Westlake Chemical Corporation from March 2006 to February 2007. Prior to joining Westlake, Mr. Gibbons was with Valero Energy Corporation for 23 years, holding positions of increasing responsibility ending as Executive Vice President and Chief Financial Officer.

Thomas P. Murphy joined the Company in June 2012 as Senior Vice President and Chief Operations Officer. From 2009 to 2012, Mr. Murphy worked at Woodside Energy USA Inc. as Vice President Engineering and Operations. From 2008 to 2009 he worked for PetroQuest Energy, Inc. as Vice President Engineering. From 2000 to 2008, Mr. Murphy worked for Devon Energy Corporation in a variety of positions, including Gulf of Mexico Deep-Water Development Supervisor, New Business Development Supervisor and culminating in his position as Sr. Exploration Advisor.

Stephen L. Schroeder joined the Company in 1998 and served as Production Manager from 1999 until 2005. In 2005, Mr. Schroeder was named Vice President of Production and in July 2006 he was named Senior Vice President and Chief Operating Officer. In June 2012, Mr. Schroeder was named Senior Vice President and Chief Technical Officer. 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." The following table sets forth the high and low sales prices of our common stock as reported on the NYSE:

	High	Low
2017:		
First Quarter	$ 3.39	$ 2.50
Second Quarter	2.81	1.85
Third Quarter	3.69	1.81
Fourth Quarter	3.68	2.60
2016:		
First Quarter	$ 3.50	$ 1.23
Second Quarter	2.74	1.93
Third Quarter	2.35	1.51
Fourth Quarter	3.47	1.31

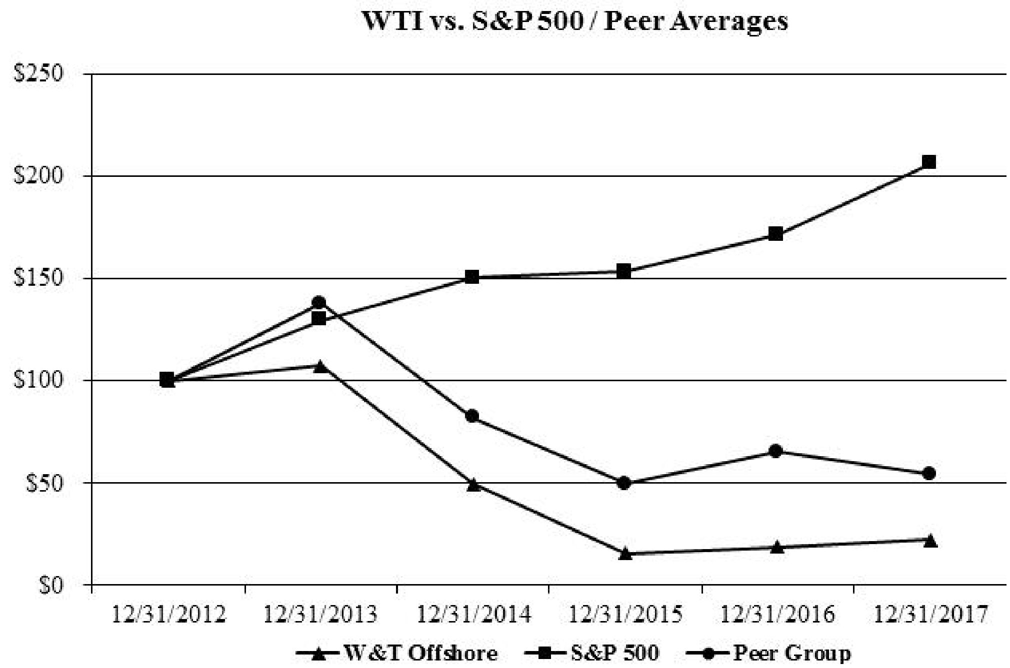
As of February 28, 2018, there were 195 registered holders of our common stock.

Dividends

During 2017 and 2016, 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 Annual Report on 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., SM Energy Co., and Stone Energy Corp. Three of the companies in our 2016 peer group have been delisted as of December 31, 2017 and have been excluded from the 2017 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 10 –Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 in this Form 10-K.

Issuer Purchases of Equity Securities

For the year 2017, 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, 2017 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, 2017 - October 31, 2017	N/A	N/A	N/A	N/A
November 1, 2017 - November 30, 2017	N/A	N/A	N/A	N/A
December 1, 2017 - December 31, 2017	505,087	$ 2.60	N/A	N/A

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,				
	2017	2016	2015	2014	2013
	(In thousands, except per share data)				
Consolidated Statement of Operations Information:					
Revenues:					
Oil	$ 340,010	$ 268,950	$ 349,191	$ 652,776	$ 718,944
NGLs	32,257	26,429	27,665	72,837	73,345
Natural gas	108,923	100,405	123,435	217,816	189,290
Other	5,906	4,202	6,974	5,279	2,509
Total revenues	487,096	399,986	507,265	948,708	984,088
Operating costs and expenses:					
Lease operating expenses	143,738	152,399	192,765	264,751	270,839
Production taxes	1,740	1,889	3,002	7,932	7,135
Gathering and transportation	20,441	22,928	17,157	19,821	17,510
Depreciation, depletion and amortization	138,510	194,038	373,368	490,469	430,611
Asset retirement obligations accretion	17,172	17,571	20,703	20,633	20,918
Ceiling test write-down of oil and natural gas properties	—	279,063	987,238	—	—
General and administrative expenses	59,744	59,740	73,110	86,999	81,874
Derivative (gain) loss	(4,199)	2,926	(14,375)	(3,965)	8,470
Total costs and expenses	377,146	730,554	1,652,968	886,640	837,357
Operating income (loss)	109,950	(330,568)	(1,145,703)	62,068	146,731
Interest expense, net of amounts capitalized	45,836	92,271	97,336	78,396	75,581
Gain on exchange of debt	7,811	123,923	—	—	—
Other (income) expense, net	4,812	(6,520)	4,663	(208)	(8,946)
Income (loss) before income tax expense (benefit)	67,113	(292,396)	(1,247,702)	(16,120)	80,096
Income tax expense (benefit)	(12,569)	(43,376)	(202,984)	(4,459)	28,774
Net income (loss)	$ 79,682	$ (249,020)	$ (1,044,718)	$ (11,661)	$ 51,322
Basic and diluted earnings (loss) per common share	$ 0.56	$ (2.60)	$ (13.76)	$ (0.16)	$ 0.68
Dividends on common stock	—	—	—	30,260	58,846
Cash dividends per common share	—	—	—	0.40	0.78
Consolidated Cash Flow Information:					
Net cash providing by operating activities	$ 159,408	$ 14,180	$ 133,228	$ 474,821	$ 562,708
Capital expenditures - oil and natural gas properties (1)	130,048	48,606	230,161	626,612	634,378

	December 31,				
	2017	2016	2015	2014	2013
	(In thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 99,058	$ 70,236	$ 85,414	$ 23,666	$ 15,800
Total assets	907,580	829,726	1,208,022	2,689,508	2,497,180
Long-term debt (including current portion)	992,052	1,020,727	1,196,855	1,352,120	1,195,883
Shareholders' equity (deficit)	(573,508)	(659,037)	(526,491)	509,308	540,610

(1) Reported on an accrual basis

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,				
	2017	**2016**	**2015**	**2014**	**2013**
Reserve Data: (1)					
Estimated net proved reserves					
Oil (MMBbls)	34.4	32.9	35.5	61.7	58.5
NGLs (MMBbls)	7.8	8.2	6.6	15.8	15.9
Natural Gas (Bcf)	192.2	197.8	205.4	254.9	259.9
Total barrel equivalents (MMBoe)	74.2	74.0	76.4	120.0	117.7
Total natural gas equivalents (Bcfe)	445.4	444.0	458.1	720.0	705.9
Proved developed producing (MMBoe)	54.5	47.3	57.6	68.7	60.6
Proved developed non-producing (MMBoe)	7.7	17.4	11.4	14.6	25.5
Total proved developed (MMBoe)	62.2	64.7	69.0	83.3	86.1
Proved undeveloped (MMBoe)	12.0	9.3	7.4	36.7	31.6
Proved developed reserves as %	83.8%	87.4%	90.3%	69.4%	73.2%
Reserve additions (reductions) (MMBoe):					
Revisions (2)	9.6	13.0	(12.7)	4.1	(3.9)
Extensions and discoveries	5.2	—	4.1	9.7	20.2
Purchases of minerals in place	—	—	1.0	6.1	2.4
Sales of minerals in place (3)	—	—	(19.0)	—	(0.5)
Production	(14.6)	(15.4)	(17.0)	(17.6)	(18.0)
Net reserve additions (reductions)	0.2	(2.4)	(43.6)	2.3	0.2

(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 2015, sales of minerals in place related primarily to the sale of the Yellow Rose field.

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,				
	2017	2016	2015	2014	2013
Operating: (1)					
Net sales:					
Oil (MBbls)	7,064	7,201	7,751	7,176	7,018
NGLs (MBbls)	1,382	1,542	1,604	2,112	2,091
Oil and NGLs (MBbls)	8,446	8,743	9,355	9,288	9,110
Natural gas (MMcf)	36,754	39,731	46,163	50,088	53,257
Total oil equivalent (MBoe)	14,571	15,365	17,049	17,636	17,986
Total natural gas equivalents (MMcfe)	87,428	92,188	102,294	105,815	107,915
Average daily equivalent sales (Boe/day)	39,921	41,980	46,709	48,317	49,276
Average daily equivalent sales (Mcfe/day)	239,528	251,879	280,256	289,904	295,657
Average realized sales prices:					
Oil ($/Bbl)	$ 48.13	$ 37.35	$ 45.05	$ 90.96	$ 102.44
NGLs ($/Bbl)	23.35	17.14	17.25	34.49	35.07
Oil and NGLs ($/Bbl)	44.08	33.79	40.28	78.13	86.97
Natural gas ($/Mcf)	2.96	2.53	2.67	4.35	3.55
Oil equivalent ($/Boe)	33.02	25.76	29.34	53.49	54.58
Natural gas equivalent ($/Mcfe)	5.50	4.29	4.89	8.92	9.10
Average per Boe ($/Boe):					
Lease operating expenses	$ 9.86	$ 9.92	$ 11.31	$ 15.01	$ 15.06
Gathering and transportation	1.40	1.49	1.01	1.14	0.95
Production costs	11.26	11.41	12.32	16.15	16.01
Production taxes	0.12	0.12	0.17	0.42	0.42
DD&A	10.68	13.77	23.11	28.98	25.10
General and administrative expenses	4.10	3.89	4.29	4.93	4.55
	$ 26.16	$ 29.19	$ 39.89	$ 50.48	$ 46.08
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 1.64	$ 1.65	$ 1.88	$ 2.50	$ 2.51
Gathering and transportation	0.23	0.25	0.17	0.19	0.16
Production costs	1.87	1.90	2.05	2.69	2.67
Production taxes	0.02	0.02	0.03	0.07	0.07
DD&A	1.78	2.30	3.85	4.83	4.18
General and administrative expenses	0.68	0.65	0.71	0.82	0.76
	$ 4.35	$ 4.87	$ 6.64	$ 8.41	$ 7.68
Wells drilled (gross):					
Offshore	5	1	5	6	6
Onshore	—	—	5	33	40
Productive wells drilled (gross):					
Offshore	4	1	5	6	5
Onshore	—	—	5	33	40

(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.

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 49 offshore fields in federal and state waters (47 producing and two fields capable of producing). We currently have under lease approximately 700,000 gross acres, with approximately 470,000 gross acres on the shelf and approximately 230,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 135 offshore structures, 87 of which are located in fields that 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.

In managing our business, we are focused on optimizing production and growing 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 our commodities produced (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 impact our cash flows and margins. During 2017, commodity prices improved from the low price levels experienced during 2016 and 2015, but were nonetheless below the levels realized in years prior to 2015. Our margins in 2017 have improved from 2016 and 2015 levels, and are approaching the margin levels achieved prior to 2015. Although we have historically grown our reserves and production through acquisitions and our drilling programs, for the last three years, we have focused on increasing reserves and production through drilling and through projects to optimize production on existing wells. While our production decreased 5.2% in 2017 from the prior year, our reserves increased more than production and resulted in a net increase in reserves year-over-year. The increase in proved reserves is a result of drilling, recompletion and workover effects, and improved commodity prices. During 2017, we drilled five wells on the continental shelf, four of which were successful, and began producing during 2017. Our plans for the short-term include operating within cash flow, maintaining liquidity, meeting our financial obligations, establishing a drilling joint venture to provide drilling capital on a promoted basis and pursuing acquisitions meeting our criteria. See *Liquidity and Capital Resources - Drilling Joint Venture* under this Item 7 in this Form 10-K for additional information on the drilling joint venture.

See *Properties – Proved Reserves* under Part I, Item 2; *Selected Financial Data* under Part II, Item 6 and *Financial Statements and Supplementary Data – Note 21 – 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. During 2017 and 2016, our volumes included production from the deepwater fields, Big Bend and Dantzler, which commenced production in late 2015. Both fields are composed of mostly oil and NGLs, having over 75% of reserves in oil and NGLs on a Boe basis. As of December 31, 2017, the Big Bend field was in our top ten fields based on reserves, net to our interest, on a Boe basis.

In September 2016, we consummated the Exchange Transaction whereby we exchanged approximately $710.2 million principal amount, or 79%, of our Unsecured Senior Notes for $301.8 million principal amount of new secured notes and 60.4 million shares of our common stock, and closed on a new $75.0 million 1.5 Lien Term Loan. The funds from the 1.5 Lien Term Loan were used to partially pay down borrowings outstanding on the revolving bank credit facility to maintain liquidity and to pay transaction costs associated with the Exchange Transaction. 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, the new debt instruments and the accounting for the transaction.

In October 2015, we sold our interests in the Yellow Rose onshore field in the Permian Basin to Ajax. Our interest in the field covered approximately 25,800 net acres. During 2015, the Yellow Rose field accounted for approximately 5% and 6% of our production and revenues, respectively. In connection with the sale, we retained a non-expense bearing overriding royalty interest ("ORRI") equal to a variable percentage in production from the working interests sold, which percentage varies on a sliding scale from one percent for each month that the prompt month New York Mercantile Exchange ("NYMEX") trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel. Internal estimates of proved reserves at the date of the sale were 19.0 MMBoe, consisting of approximately 71% oil, 11% NGL and 18% natural gas. Including adjustments from an effective date of January 1, 2015, the adjusted sales price was $370.9 million and the buyer assumed the ARO associated with our interests in the Yellow Rose field, which we had estimated at $6.9 million at the time of the sale. We used a portion of the proceeds of the sale to repay all the outstanding borrowings under our revolving bank credit facility, while the remaining balance of approximately $100 million was added to available cash. See *Financial Statements and Supplementary Data – Note 7 – Divestitures* under Part II, Item 8 in this Form 10-K for additional information.

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 2017 were comprised of approximately 49% oil and condensate, 9% NGLs and 42% 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 2017, our combined total production of oil, NGLs and natural gas was 5.2% below 2016, primarily due to natural production declines, partially offset by production from wells drilled and completed during 2017 and 2016.

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 2017, crude oil, NGL, and natural gas realized prices were significantly above 2016 realized prices, increasing 28.9%, 36.2% and 17.0%, respectively. In January 2018, realized prices have increased from December 31, 2017 levels. In addition, our lease operating costs in 2017 declined from the prior year, both on an absolute and per Boe basis.

The U.S. Energy Information Administration ("EIA") estimated worldwide crude oil and petroleum liquids inventory draws averaged 0.4 million barrels per day during 2017, which was the first year of inventory draws since 2013. These inventory draws were supportive to higher crude oil prices worldwide. EIA currently forecasts worldwide crude oil and petroleum liquids inventories to increase by 0.2 million barrels per day and 0.3 million barrels per day in 2018 and 2019, respectively.

EIA estimates worldwide petroleum production increased by 0.7 million barrels per day in 2017 over 2016. The increase in 2017 over 2016 was primarily in the U.S. and Canada, partially offset by decreases in Russia and China. For 2018 and 2019, EIA forecasts year over year production increases of 2.4 million barrels per day and 1.8 million barrels per day, respectively, with the increases coming primarily from the U.S. and partially from Canada, Brazil and the Organization of the Petroleum Exporting Countries ("OPEC") for both periods. Petroleum liquid consumption was estimated to increase by 1.4 million barrels per day in 2017 over 2016 with the largest increases coming from China and the U.S. For 2018 and 2019, EIA forecasts year over year consumption increases of 1.7 million barrels per day and 1.6 million barrels per day, respectively, with the increases coming primarily from China, other Asian countries, and the U.S. although increases are forecasted for almost every country or groups of countries reported by EIA.

According to data provided by EIA, 2017 U.S. crude oil production (excluding other petroleum liquids) increased by 5% from 2016 and is expected to further increase year over year by 10% and 6% in 2018 and 2019, respectively. If EIA's forecast is achieved in 2018, oil production in the U.S will be at the highest level in recorded history, surpassing the current record set in 1970. Net imports of crude oil in the U.S. decreased 7% in 2017 compared to 2016, and are forecasted to decrease year-over-year in 2018 and 2019 by 8% and 9%, respectively. As noted below, the number of rigs drilling for oil has more than doubled compared to 2016.

Geopolitical events could greatly affect the prices for oil, natural gas and other petroleum products. While these events are difficult to predict, countries like Venezuela, Nigeria, Libya, and Middle East countries have had, and could continue to have, disruptions due to political and economic factors outside of production issues. The proposed initial public offering of Saudi Arabian American Oil Company (Aramco) may provide an additional incentive for Saudi Arabia to take actions to maintain or increase crude oil prices to help drive the share value prior to and after the offering.

During 2017, our average realized oil sales price was $48.13 per barrel, up from $37.35 per barrel (28.9% higher) for 2016. The two primary benchmarks are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $50.80 per barrel for 2017, up from $43.29 per barrel (17.3% higher) for 2016. Brent crude oil prices averaged $54.12 per barrel for 2017, up from $43.67 per barrel (23.9% higher) for 2016. The reductions in international crude oil supply and rising U.S. crude oil production puts price pressure on the discount of WTI to Brent , as the Brent-to-WTI premium increased in 2017 to over $3.00 per barrel compared to less than $0.50 per barrel in 2016.

Our average realized oil sales price ($48.13 per barrel compared to a WTI benchmark price of $50.80 per barrel) 2017 differs from the benchmark crude prices due to premiums or discounts (referred to as differentials), crude quality adjustments, volume weighting and other factors. All of our 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 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 2017 were a negative $0.95, a positive $2.85 and a positive $2.44 per barrel, respectively, compared to a negative $3.57, a positive $1.70 and a positive $0.84 per barrel, respectively, for 2016. The majority of our crude oil is priced similar to Poseidon and therefore, experienced negative differentials for 2017. In addition, a few of our crude oil fields have a negative quality bank adjustment. However, our oil price differentials turned positive in the last two months of 2017 as the Brent-WTI differential widened.

EIA projects average crude oil prices for both WTI and Brent to increase by approximately $5.00 per barrel in 2018 compared to 2017. EIA's forecast of crude oil prices for WTI and Brent are expected to increase by approximately $2.00 per barrel each, for the year 2019 compared to 2018. OPEC and certain non-OPEC countries agreed in November 2017 to extend their previously agreed on production cuts to the end of 2018 in an effort to reduce global inventories. In the U.S., onshore areas such as the Permian Basin, Eagle Ford area, and the Bakken region are expected to have increased production in 2018 over 2017 as the areas have shown to be responsive to price change. Prices in the mid $50's are expected to increasing drilling activity in these areas, which can occur fairly quickly. However, lasting upward and downward price movements could be limited over the next year because a substantial majority of U.S. producers have locked in their prices with financial commodity derivatives allowing them to continue to drill and produce regardless of price changes. During 2017, the U.S. dollar weakened relative to other major currencies, which had a positive effect on crude oil prices. Because all barrels are traded in U.S. dollars, as the U.S. dollar loses strength, crude oil prices are less expensive in other currencies and thus spur consumption.

During 2017, our average realized NGLs sales price increased 36.2% compared to 2016. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During 2017, the average price for domestic ethane increased 20% and the average domestic propane price increased 59% from the average 2016 prices. The average 2017 prices for other domestic NGLs increased from the average 2016 prices, ranging from 21% to 42%. We believe the increase in prices for NGLs is mostly a function of the change in oil and natural gas prices. Per EIA, production of ethane was estimated to increase 9% for 2017 compared to 2016 and propane production was estimated to increase by 5% for 2017 compared to 2016. Ethane inventories as of year-end 2017 increased 23% over year-end 2016 levels. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Ethane production in 2018 and 2019 is forecast to increase year-over-year leading to further inventory builds. Two new petrochemical plants came on line in the first half of 2017 and five more are expected to be operational by the end of 2018. On the other hand, 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 were 26% lower at the end of 2017 compared to the same period last year.

During 2017, our average realized natural gas sales price increased 17.0 % compared to 2016. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 18.5% higher in 2017 compared to 2016. 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 2017 were 5% lower than year-end 2016, and were 8% below the five-year average.

EIA projects natural gas prices to be relatively flat in 2018 and 2019, decreasing 3% in 2018 from 2017 and increasing 1% in 2019 from 2018. U.S. supply is projected to be slightly above consumption in 2018 and 2019, resulting in minor inventory increases. As a result, excess inventory is not expected to be significantly changed, which limits any significant upward price movement. EIA's estimate of fuel used for electrical power generation in 2017 was 32% from natural gas, 30% from coal and 17% from renewable sources (includes hydropower and wind) and 21% for all other sources. For 2018 and 2019, EIA forecasts electrical power from natural gas to increase to 33% and 34%, respectively, with the offset primarily in electrical power generation from coal.

During 2017, the number of working rigs drilling for oil and natural gas in the U.S. were higher than 2016 levels for land based rigs. During 2017, offshore rigs were approximately the same as 2016 levels during most of the year, but were lower in the fourth quarter of 2017 compared to levels in the fourth quarter of 2016. According to Baker Hughes, the oil rig count at December 31, 2017 and 2016 was 747 and 525, respectively (a 42% increase). The U.S. natural gas rig count at December 31, 2017 and 2016 was 182 and 132, respectively (a 38% increase). In the Gulf of Mexico, the number of working rigs was 18 rigs (14 oil and four natural gas) at December 31, 2017, and 22 rigs (22 oil and no natural gas) at December 31, 2016. The majority of working rigs in the Gulf of Mexico are currently "floaters" with very few jack-up rigs working.

We also believe that private equity and hedge funds are increasingly demanding cash flow positive projects in shale resource projects as opposed to solely focusing on increased reserves and production growth. This may decrease future drilling in the shale resource areas, which in turn would decrease future production.

As required by the full cost accounting rules, we perform our ceiling test calculation each quarter using the SEC pricing guidelines, which require using the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price adjusted for price differentials. During 2017, we did not have any ceiling-test write downs. Due to the lower prices of oil and natural gas occurring during 2016 and 2015, we had ceiling-test write downs in 2016 and 2015 of $279.1 million and $987.2 million, respectively. The incurrence of ceiling-test write downs is dependent primarily on the price of crude oil and natural gas, but also is affected by quantities of proved reserves, future development costs and future lease operating costs. Using information available as of the filing date of this Form 10-K, we do not anticipate a ceiling-test write downs in the first quarter of 2018.

As of December 31, 2017, we had $99.1 million of available cash and $149.7 million available on our revolving bank credit facility, which currently has a borrowing base of $150.0 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 2017, our capital expenditures for oil and gas properties and equipment on an accrual basis were $130.0 million, which was a substantial increase from the $48.6 million of capital expenditures in 2016, but below the capital expenditures in 2015 and 2014, which were $230.1 million and $626.6 million, respectively. For 2018, we have set our initial capital expenditure budget at $130.0 million is composed of select lower-risk, high-return, oil-focused projects combined with higher-risk, higher return, oil-focused projects that, assuming success, would be placed on production fairly quickly. We have flexibility in our capital expenditure programs as we have no long-term rig commitments and no pressure from co-owners to drill or complete a well. Some of our expenditures incurred during 2017 impacted our production for 2017, but most of the impact is expected to occur in 2018 and beyond. In addition, we spent $72.4 million in 2017 and $72.3 million in 2016 for ARO and plan to spend $23.6 million in 2018 for ARO.

Our operating costs in 2017 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 2017, our lease operating expenses decreased 5.7% compared to 2016 on an absolute basis. The decrease was primarily due to lower costs of goods and services from vendors. Additionally, we received higher product handling arrangement ("PHA") fees in 2017 for certain fields as compared to 2016, which are recorded as credits to expense. 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 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 $273.8 million in bonds related to ARO and have restricted deposits for certain ARO arrangements. Over the last ten years, we have spent over $750 million for ARO. We estimated the present value of our liability related to our ARO at $300.4 million as of December 31, 2017, of which $23.6 million is estimated to be spent during 2018. 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. Overall, service costs related to plugging and abandonment were relatively lower in 2017 compared to 2016 on a per project basis.

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.

Results of Operations

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, Viosco Knoll 823 (“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 ("G&A"). 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 10 – Share-Based and Cash-Based Incentive Compensation* 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 8 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense. Interest expense was $45.8 million in 2017, decreasing 50.3% from $92.3 million (net of capitalized interest) in 2016. The decrease was primarily attributable to the Exchange 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. 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, an additional net gain of $7.8 million was recognized primarily as a result of paying interest in cash on the Second Lien PIK Toggles Notes and the Third Lien PIK Toggle Notes versus paying the interest in kind. The cash interest payments on Second Lien PIK Toggles Notes and the Third Lien PIK Toggle Notes lowered the carrying value of the respective notes under Accounting Standard Codification 470-60, *Troubled Debt Restructuring* ("ASC 470-60"), resulting in the recognition of a non-cash gain. The cash payments have 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 $4.8 million of net expense and $6.5 million of net income, 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, $7.7 million of income was recorded related to the settlements with certain insurance companies. Also, in 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 17 – 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 Internal Revenue Code ("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. See *Financial Statements and Supplementary Data – Note 12 – Income Taxes* under Part II, Item 8 in this Form 10-K for additional information.

On December 22, 2017, the TCJA was enacted into law. 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. 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. However, due to the timing and the complexity involved in applying the provisions of the TCJA, our application of the TCJA may require further adjustments during 2018 in the determination of the final effects on our financial statements. For 2018, we do not expect to make any significant income tax payments.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Revenues. Total revenues decreased $107.3 million, or 21.1%, to $400.0 million in 2016 compared to $507.3 million in 2015. Oil revenues decreased $80.2 million, or 23.0%, NGLs revenues decreased $1.2 million, or 4.5%, natural gas revenues decreased $23.0 million, or 18.7%, and other revenues decreased $2.8 million. The oil revenue decrease was attributable to a 17.1% per barrel decrease in the average realized sales price to $37.35 per barrel in 2016 from $45.05 per barrel in 2015 and a 7.1% decrease in sales volumes. The NGLs revenue decrease was attributable to a 0.6% decrease in the average realized sales price to $17.14 per barrel in 2016 from $17.25 per barrel in 2015 and a decrease of 3.9% in sales volumes. The decrease in natural gas revenue was attributable to a 5.2% decrease in the average realized natural gas sales price to $2.53 per Mcf in 2016 from $2.67 per Mcf for 2015 and a 13.9% decrease in sales volumes. We experienced increases in production at the Big Bend and Dantzler fields, which began production in the fourth quarter of 2015. Also, production increases were achieved at the Ewing Bank 910 field, the Main Pass 108, the Main Pass 98 field and the East Cameron 321 field. Offsetting these production increases were production declines primarily from the sale of the Yellow Rose field in October 2015 (0.8 MMBoe); decreases at Mahogany, Matterhorn and Garden Banks 302 (Power Play) and other fields due to natural production declines; and various operational issues. Production deferrals, which occurred at Mahogany and other locations, were attributable to third-party pipeline outages, operational issues, and maintenance. For 2016, production deferrals were estimated to be 1.8 MMBoe compared to 2.0 MMBoe for 2015.

Revenues from oil and liquids as a percent of our total revenues were 73.8% for 2016 compared to 74.3% for 2015. NGLs realized sales prices as a percent of crude oil realized prices increased to 45.9% for 2016 compared to 38.3% for 2015 as crude oil prices continued to decline during most of 2016.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $40.4 million, or 20.9%, to $152.4 million in 2016 compared to 192.8 million in 2015. On a per Boe basis, lease operating expenses decreased to $9.92 per Boe during 2016 compared to $11.31 per Boe during 2015. On a component basis, base lease operating expenses decreased $18.1 million, workover expense decreased $12.6 million, insurance premiums decreased $6.6 million, facilities maintenance decreased $2.1 million and insurance reimbursements increased $1.0 million (offset to expense). Base lease operating expenses decreased primarily due to lower costs from service providers and elimination of field expenses related to the sale of the Yellow Rose field, which was sold in October 2015; partially offset by increases in expenses related to our new deepwater fields at Dantzler and Big Bend; and lower PHA fees (cost offsets) at our Matterhorn field. The decrease in workover costs was primarily due to the sale of the Yellow Rose field and various activities that occurred in 2015 that did not reoccur in 2016. Insurance premium reductions were primarily due to revisions in the Energy Package related to named windstorms coverage.

Production taxes. Production taxes decreased to $1.9 million, or 37.1%, during 2016 compared to $3.0 million in 2015 primarily due to lower commodity prices and the sale of the Yellow Rose field. Our 2016 production taxes were not a large component of our operating costs. Most of our production was from federal waters where there are no production taxes, while onshore and state water operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased to $22.9 million, or 33.6%, in 2016 compared to $17.2 million in 2015 primarily due to production increases from the Big Bend and Dantzler fields, both of which began producing in the fourth quarter of 2015.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $13.77 per Boe for 2016 from $23.11 per Boe for 2015. On a nominal basis, DD&A decreased to $211.6 million, or 46.3%, for 2016 from $394.1 million in 2015. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2016 and 2015, and lower capital expenditures in relation to DD&A expense, which lowered the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field proved reserves. Other factors affecting the DD&A rate were changes to future development costs on remaining proved reserves and changes to proved reserves.

Ceiling test write-down of oil and natural gas properties. For 2016 and 2015, we recorded non-cash ceiling test write-downs of $279.1 million and $987.2 million, respectively, as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The ceiling test write-downs were the result of decreases in prices 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, and above under the section *Overview* in this Item regarding our prospects for a future significant ceiling test write-downs.

General and administrative expenses. G&A decreased to $59.7 million, or 18.3%, for 2016 from $73.1 million for 2015 primarily due to decreases in headcount related expense (salaries, benefits, and contractor expenses), elimination of certain employee benefits, increased reimbursements from stop-loss medical policies, and reductions in legal settlements, partially offset by higher legal costs. G&A on a per BOE basis was $3.89 Boe for 2016 compared to $4.29 per Boe for 2015. See *Financial Statements and Supplementary Data – Note 10 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 in this Form 10-K for additional information

Derivative (gain) loss. For 2016, there was a $2.9 million derivative net loss recorded for derivative contracts for crude oil and natural gas. At December 31, 2016, we did not have any open derivative contracts. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For 2015, there was a $14.4 million derivative net gain recorded for derivative contracts for crude oil and natural gas. For both periods, the amount includes changes in the fair value of commodity derivative contracts. See *Financial Statements and Supplementary Data – Note 8 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense. Interest expense incurred was $92.8 million in 2016, compared to $104.6 million in 2015. The decrease was primarily attributable to the Exchange Transaction. Interest expense was reduced for the Unsecured Senior Notes exchanged on September 7, 2016. For the debt issued in the Exchange Transaction, undiscounted future cash flows (principal, PIK and cash interest) were recorded as part of the carrying value of the debt under ASC 470-60; therefore, no interest expense was recorded for the debt issued in the Exchange Transaction for the period of September 7, 2016 to December 31, 2016. In addition, interest expense was lower due to lower average borrowings on the revolving bank credit facility. During 2016 and 2015, interest of $0.5 million and $7.3 million, respectively, was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to the sale of the Yellow Rose field during the fourth quarter of 2015 and reclassifying all other remaining unevaluated properties to the full-cost pool during 2016.

Gain on exchange of debt. In 2016, a gain of $123.9 million was recorded 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.

Other (income) expense, net. Other (income) expense, net was income of $6.5 million in 2016 and was an expense of $4.7 million for 2015. For 2016, $7.7 million of income was recorded related to the settlements with certain insurance companies. In both 2016 and 2015, 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 and 2015 of $1.4 million and $3.2 million, respectively, in the unamortized debt issuance costs related to the revolving bank credit facility. In addition, during 2015, a net loss on sale of assets of $1.0 million was recorded primarily related to the sale of computer equipment used for backup processes.

Income tax benefit. Our income tax benefit for 2016 and 2015 was $43.4 million and $203.0 million, respectively, with the change attributable primarily to the deferred tax assets and the valuation allowance recorded for the respective periods. Our annual effective tax rate for 2016 and 2015 was not meaningful for either year, and differs from the federal statutory rate of 35% primarily due to the valuation allowances recorded for our deferred tax assets in both years. During 2016 and 2015, we recorded increases to the valuation allowance of $52.9 million and $232.9 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. See *Financial Statements and Supplementary Data – Note 12 – 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. If such events were to occur in the future, we may seek relief under the U.S. Bankruptcy Code, which relief may include (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks.

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;
- further 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.

During 2016, we engaged legal and financial advisors to assist the Board of Directors and our management team to evaluate the various alternatives available to us. On September 7, 2016, we consummated the Exchange Transaction, which changed our debt and equity structure. See *Financial Statements and Supplementary Data - Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information.

During 2017, we paid the interest payment for the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes due in May 2017 and June 2017, respectively, in cash rather than in kind. These cash payments and the cash payments related to the 1.5 Lien Term Loan are reported in the financing section of the Consolidated Statements of Cash Flows under ASC 470-60. In addition, the cash interest payments on the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes lowered the carrying value of the respective notes under ACS 470-60, resulting in the recognition of a non-cash gain in 2017.

During 2018, the paid-in-kind option for the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes will expire in March 2018 and September 2018, respectively. Subsequent to the expiration of the paid-in-kind option, interest may only be paid in cash.

We are reviewing several alternatives to address the upcoming maturity of our revolving bank credit facility on November 8, 2018 and the repayment or refinancing of our Unsecured Senior Notes to address the maturity acceleration of certain of our debt instruments, which is described below. We believe the maturity of the revolving bank credit facility can be extended if we are able to extinguish the Unsecured Notes and extended further if we are able to extinguish the 1.5 Lien Term Loan, both of which mature in 2019.

Our Unsecured Senior Notes with total outstanding principal of $189.8 million mature on June 15, 2019. Our 1.5 Lien Term Loan with outstanding principal of $75.0 million matures on November 15, 2019. Our Second Lien Term Loan with outstanding principal of $300.0 million matures on May 15, 2020. Our Second Lien PIK Toggle Notes with current outstanding principal of $171.8 million matures on May 15, 2020, and our Third Lien PIK Toggle Notes with outstanding principal of $153.2 million matures on June 15, 2021. Each of our 1.5 Lien Term Loan and the Third Lien PIK Toggle Notes contain terms that accelerate their maturities to February 28, 2019 if all of the outstanding Unsecured Senior Notes are not refinanced, paid off, defeased, or otherwise extinguished prior to February 28, 2019. Assuming full utilization of the PIK option for our Third Lien PIK Toggle Notes, the combined principal of our 1.5 Lien Term Loan and our Third Lien PIK Toggle Notes would be $239.5 million on February 28, 2019. Each of our Second Lien Term Loan and Second Lien PIK Toggle Notes require us to offer to repay or repurchase the Second Lien Term Loan and Second Lien PIK Toggle Notes, as applicable, at par plus accrued and unpaid interest if by May 16, 2019, the aggregate outstanding principal amount of Unsecured Senior Notes that have not been repurchased, redeemed, discharged, defeased or called for redemption exceeds $50.0 million. Certain amendments under the 1.5 Lien Term Loan and the Credit Agreement will likely be required in the event replacement financing is not utilized.

We expect to build sufficient cash balances in 2018 to be able to redeem, repurchase or refinance the Unsecured Senior Notes and repay or refinance our 1.5 Lien Term Loan. This should enable us to amend our revolving bank credit facility in such a manner that will permit an extension of the maturity of such facility. There can be no assurance that lenders will extend our revolving bank credit facility maturity, but under current market conditions and based on the outlook of our cash position in 2018, we believe our lenders or replacement lenders will be amenable to participating in a refinancing or other liability management transaction.

Credit Agreement. As indicated above, our revolving bank credit facility matures on November 8, 2018. Availability on our revolving bank credit facility as of December 31, 2017 was $149.7 million. At December 31, 2017 and December 31, 2016, no amounts were outstanding and letters of credit were minimal. During 2017, no borrowings were made on the revolving bank credit facility.

Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The 2017 fall redetermination reaffirmed the borrowing base amount at $150.0 million. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. The revolving bank credit facility is secured and is collateralized by substantially all of our oil and natural gas properties.

We currently have 20 lenders within the revolving bank credit facility, with commitments ranging from $4.1 million to $11.6 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, 2017.

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.

Drilling Joint Venture: To provide additional financial flexibility, as we have previously reported, throughout 2017 and now into 2018 we have been working to establish a drilling joint venture with private investors. We are in final stages of establishing a drilling joint venture to be formed with private investors that will allow us to drill and exploit assets on a promoted basis and with reduced capital outlay. We have completed negotiations with an initial group of investors, the terms of which are subject to funding at an initial closing expected to occur by mid-March. It is expected that entities owned and controlled by Tracy W. Krohn, Chairman and Chief Executive Officer of the Company, and his family will invest on the same terms as are negotiated with the unaffiliated investors to acquire an approximate 4% interest in the drilling joint venture. More investors may join the joint venture before or after the initial closing. If completed, this joint venture arrangement should reduce cash commitments for capital expenditures depending on the level of outside investor participation.

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 flow and working capital. Net cash provided by operating activities for 2017 was $159.4 million, compared to $14.2 million for 2016. Cash flows from operating activities and income taxes, (before changes in working capital, insurance reimbursements, escrow deposits and ARO settlements), were $235.6 million in 2017 compared to $103.1 million in 2016. The increase in cash flows was primarily due to higher realized prices for all our commodities - oil, NGLs and natural gas, lower operating expenses and lower interest payments, partially offset by lower production volumes. Our combined average realized sales price per Boe increased 28.2%, which increased revenues $100.8 million. Partially offsetting were decreased combined volumes on a Boe basis of 5.2%, which lowered revenues by $15.4 million. Additionally, cash operating expenses and interest expenses combined were 13.2% lower on a per Boe basis, which increased cash flows from operating activities by $58.2 million. Interest payments related to the New Debt are reported within cash flows from financing activities under ASC 470-60.

Other items affecting operating cash flows for 2017 were ARO settlements of $72.4 million and an escrow deposit related to the Apache matter of $49.5 million, partially offset by insurance reimbursements of $31.7 million.

Net cash used in investing activities of oil and gas properties and equipment in 2017 was $107.1 million compared to $82.4 million in 2016. Both of these represent our investments in oil and gas properties and equipment in the Gulf of Mexico. There were no acquisitions during either year. Investments in oil and natural gas properties on an accrual basis during 2017 were $130.0 million compared to $48.6 million for 2016. In addition, adjustments from working capital changes associated with investing activities decreased net cash used by $23.9 million in 2017 compared to adjustments increasing net cash used of $35.2 million for 2016. Both of these adjustments are made to present capital expenditures on a cash basis.

Net cash used in financing activities for 2017 was $23.5 millionand net cash provided by financing activities for 2016 was $53.0million. The net cash used by financing activities for 2017 was primarily attributable to the interest payments on the 1.5 Lien Term Loan, the Second Lien PIK Toggle Notes, and the Third Lien PIK Toggle Notes, which are reported as financing activities under ASC 470-60. The net cash provided by financing activities in 2016 was attributable to the issuance of the 1.5 Lien Term Loan, partially offset by interest payments on the 1.5 Lien Term Loan and costs related to the Debt Exchange transaction.

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. As of December 31, 2017, we did not have any outstanding open derivatives for crude oil and natural gas.

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, 2017, which includes $31.7 million collected during 2017. As of December 31, 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 $150.0 million aggregate limit covering all of our properties, subject to a retention (deductible) of $30.0 million. Included within the $150.0 million aggregate limit is total loss only ("TLO") coverage on our Mahogany platform, which has no retention. The operational and named windstorm coverages are effective for one year beginning June 1, 2017. 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, 2017 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, 2017, and our Energy Package effective on June 1, 2017, 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 $10.8 million for the May/June 2017 policy renewals compared to $8.5 million for the expiring policies. The increase in our premiums effective with the May/June 2017 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 capital expenditures on an accrual basis for exploration, development, acquisitions and other leasehold costs:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Exploration (1)	$ 57,088	$ 1,541	$ 51,768
Development (1)	71,054	45,183	160,500
Acquisition of additional interest in Fairway (2)	—	—	1,285
Acquisition of Woodside Properties (2)	—	—	214
Seismic, capitalized interest, other	1,906	1,882	16,394
Acquisitions and investments in oil and gas property/equipment	$ 130,048	$ 48,606	$ 230,161

(1) Reported geographically in the subsequent table.

(2) The amounts in 2015 represent adjustments to the purchase price for post-effective adjustments.

The following table presents our exploration and development capital expenditures on an accrual basis geographically:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Conventional shelf	$ 121,922	$ 38,631	$ 13,933
Deepwater	6,220	8,093	186,579
Deep shelf	—	—	195
Onshore	—	—	11,561
Exploration and development capital expenditures	$ 128,142	$ 46,724	$ 212,268

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

	Completed		
	2017	2016	2015
Offshore - gross wells drilled:			
Conventional shelf	4	—	—
Deepwater	—	1	5
Wells operated by W&T	4	—	—

We had an 80% success rate in 2017, 100% in 2016 and 100% in 2015. We drilled one exploration well on the conventional shelf during 2017 that was non-commercial, of which we had a 39% working interest.

During 2015, we sold our interest in the onshore Yellow Rose field. Therefore, the historical information for onshore wells was excluded from the table above.

During the first two months of 2018, we mobilized a rig to the Viosca Knoll 823 (Virgo) platform and drilled the Viosca Knoll 823 A-10 ST1 well to target depth. The A-17 well at Mahogany and the #1 well at Main Pass 286 have both been drilled to target depth. Completion operations are in progress for the A-17 well at Mahogany. The Main Pass 286 #1 well was successful and logged pay as a new field discovery. The Main Pass 286 #1 well has been cased and is waiting for development sanction, which is expected during 2018. First production is expected in early 2019.

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 four leases for approximately $0.5 million from the BOEM in the Federal Offshore Lease Sale. Per year, we acquired one lease ($0.1 million), one lease ($0.1 million) and two leases ($0.3 million) in the years 2017, 2016 and 2015, 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 2015 we sold our interest in the Yellow Rose field for $370.9 million after adjustments and reduced related ARO by $6.9 million. In 2017 and 2016, there were no property sales of significance. See *Financial Statements and Supplementary Data – Note 7 –Divestitures* under Part II, Item 8 in this Form 10-K for additional information on this divestiture.

Capital expenditures. Our initial capital expenditure budget for 2018 is $130 million, which excludes potential acquisitions, with over 50% allocated to development. Because of the level of commodity prices and the outlook for the remainder of 2018, we believe this level will enhance our liquidity capacity throughout 2018. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments. See the *Overview* section in this Item for additional information.

Income taxes. As of December 31, 2017, we have recorded a current income taxes receivable of $13.0 million and a non-current income taxes receivable of $52.1 million. The current income taxes receivable relates primarily to an estimated NOL claim for 2017, which is expected to be received during 2018. During 2017, we received $11.9 million of income tax refunds related primarily to a 2016 NOL claim carried back to 2006. The non-current income taxes receivable relates 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 timing of which cannot be estimated at this time. These receivables relate 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 claims will not be allowed in 2018 and forward. The TCJA does not affect our claims previously filed, noted above, nor does the TCJA affect the review process for such claims. For 2018, we do not expect to make any significant income tax payments.

Dividends. During 2017, 2016 and 2015, 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, 2017 and 2016 were $300.4 million and $334.4 million, respectively, recorded using discounted values. Our estimate of ARO spending in 2018 is $23.6 million. During 2017 and 2016, we revised our estimates of costs anticipated to be charged by service providers for plug 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 4 – Asset Retirement Obligations* under Part II, Item 8 in this Form 10-K for additional information regarding our ARO.

Contractual obligations. At December 31, 2017, we did not have any capital leases or open derivative contracts. The following table summarizes our significant contractual obligations by maturity as of December 31, 2017:

	Payments Due by Period as of December 31, 2017				
	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt - principal (1)	$ 906.8	$ —	$ 442.3	$ 464.5	$ —
Long-term debt - interest (2)	194.9	63.0	97.5	34.4	—
Drilling rigs	5.7	5.7	—	—	—
Operating leases	9.3	1.8	3.6	3.7	0.2
Asset retirement obligations (3)	300.4	23.6	87.2	15.8	173.8
Other liabilities and commitments (4)	69.6	7.7	14.1	10.4	37.4
Total	$ 1,486.7	$ 101.8	$ 644.7	$ 528.8	$ 211.4

(1) Principal on long-term debt assumes the PIK option is fully utilized on the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes during 2018.

(2) Interest payments were calculated through the stated maturity date of the related debt: (a) Interest on the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes was estimated assuming the principal is increased from full utilization of the remaining PIK option for these notes. (b) As no amounts were outstanding on the revolving bank credit facility as of December 31, 2017 and minimal letters of credit were outstanding, interest for the revolving bank credit facility was calculated using the commitment fee of 0.50% on the current borrowing base through the maturity date.

(3) 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, 2017 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.

(4) Other liabilities and commitments primarily consist of estimated fees for surety bonds related to obligations under certain purchase and sale agreements and for supplemental bonding for plugging and abandonment on behalf of the BOEM. As of December 31, 2017, we had approximately $291 million of bonds outstanding, which includes $274 million of bonds related to plugging and abandonment. 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. Also excluded are 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 15 – Commitments* under Part II, Item 8 in this 10-K for additional information.

Inflation and Seasonality

Inflation. For 2017, our realized prices for crude oil increased 28.9%, NGLs increased 36.2% and natural gas increased 17.0% from 2016. These are discussed in the *Overview* section above. Historically, our costs for goods and services have moved directionally with the price of crude oil, NGLs and natural gas, as these commodities affect the demand for these goods and services. Operating costs directly related to production (lease operating expenses, production taxes and gathering and transportation) measured on a $/Boe basis decreased by 1.3% in 2017 compared to 2016. These operating costs directly 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 oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with joint ownership. Under this method, 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.

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 and 2015. We did not have any ceiling test impairments in 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, 2017 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.

As a result of the TCJA being enacted on December 22, 2017, we provisionally re-measured our deferred tax assets as of December 31, 2017. Further adjustments may be required in 2018 to determine the final effects on our financial statements.

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. Under ASC 470-60, the carrying value of the New Debt is measured using all future undiscounted payments (principal and interest); therefore, no interest expense has been recorded for the New Debt in the Consolidated Statements of Operations since September 7, 2016. Thus, our reported interest expense is significantly less than the contractual interest payments and this will continue through the maturities of the New Debt. The amounts recorded for the carrying value of the New Debt were determined using certain assumptions, which primarily were: (i) the PIK options, when available, would be fully utilized and (ii) the maturity of 1.5 Lien Term Loan and the Third Lien PIK Toggle Notes would not be accelerated, which implies the Unsecured Senior Notes will be repaid prior to February 28, 2019. These assumptions may prove to be incorrect, which would change the carrying value of the New Debt.

Revenue Recognition. 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 is effective for annual and interim periods beginning after December 15, 2017. 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 is complete and we have 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. We will adopt ASU 2014-09 using the modified retrospective method that requires application of the new standard prospectively from the date of adoption with a cumulative effect adjustment, if any, recorded to retained earnings as of January 1, 2018 and revise our disclosures under ASU 2014-09 as applicable. 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, and upon further review and analysis, our application of ASU 2014-09 may need to be modified, which may require revisions to previously reported amounts.

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 2017 and had no open derivative contracts as of December 31, 2017. We do not designate our commodity derivative contracts as hedging instruments. While previous derivative contracts were intended to reduce the effects of volatile oil prices, they may also have limited income from favorable price movements. For additional details about our derivative contracts, refer to *Financial Statements and Supplementary Data – Note 8 – 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 2017 and assuming no other items had changed, our income before income tax would have decreased by approximately $48 million in 2017. If costs and expenses of operating our properties had increased by 10% in 2017, our income before income tax would have decreased by approximately $17 million in 2017. 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, 2017, we had no borrowings outstanding on our revolving bank credit facility and during 2017, we had no borrowings. The revolving bank credit facility has a variable interest rate which is primarily impacted by the rates for the London Interbank Offered Rate and the current margin ranges from 3.00% to 4.00% depending on the amount outstanding. In 2017, if interest rates would have been 100 basis points higher (an additional 1%), our interest expense would not have changed as no borrowings were made during 2017. We did not have any derivative contracts related to interest rates as of December 31, 2017.

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, 2017 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, 2017 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, 2017, 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, 2017, 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, 2017 and 2016, 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, 2017, and related notes and our report dated March 2, 2018 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
March 2, 2018

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, 2017 and 2016, 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, 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 2, 2018 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
March 2, 2018

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

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 99,058	$ 70,236
Receivables:		
Oil and natural gas sales	45,443	43,073
Joint interest	19,754	21,885
Insurance reimbursement	—	30,100
Income taxes	13,006	11,943
Total receivables	78,203	107,001
Prepaid expenses and other assets (Note 1)	13,419	14,504
Total current assets	190,680	191,741
Oil and natural gas properties and other, net - at cost: (Note 1)	579,016	547,053
Restricted deposits for asset retirement obligations	25,394	27,371
Income tax receivables	52,097	52,097
Other assets (Note 1)	60,393	11,464
Total assets	$ 907,580	$ 829,726
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$ 83,665	$ 81,039
Undistributed oil and natural gas proceeds	20,129	26,254
Asset retirement obligations	23,613	78,264
Long-term debt	22,925	8,272
Accrued liabilities (Note 1)	17,930	9,200
Total current liabilities	168,262	203,029
Long-term debt: (Note 2)		
Principal	889,790	873,733
Carrying value adjustments	79,337	138,722
Long term debt, less current portion - carrying value	969,127	1,012,455
Asset retirement obligations, less current portion	276,833	256,174
Other liabilities (Note 1)	66,866	17,105
Commitments and contingencies (Note 9)	—	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at December 31, 2017 and December 31, 2016	—	—
Common stock, $0.00001 par value; 200,000,000 shares authorized; 141,960,462 issued and 139,091,289 outstanding at December 31, 2017 and 140,543,545 issued and 137,674,372 outstanding at December 31, 2016	1	1
Additional paid-in capital	545,820	539,973
Retained earnings (deficit)	(1,095,162)	(1,174,844)
Treasury stock, at cost; 2,869,173 shares at December 31, 2017 and December 31, 2016	(24,167)	(24,167)
Total shareholders' deficit	(573,508)	(659,037)
Total liabilities and shareholders' deficit	$ 907,580	$ 829,726

See accompanying notes.

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

	Year Ended December 31, 2017	2016	2015
Revenues	$ 487,096	$ 399,986	$ 507,265
Operating costs and expenses:			
Lease operating expenses	143,738	152,399	192,765
Production taxes	1,740	1,889	3,002
Gathering and transportation	20,441	22,928	17,157
Depreciation, depletion and amortization	138,510	194,038	373,368
Asset retirement obligations accretion	17,172	17,571	20,703
Ceiling test write-down of oil and natural gas properties	—	279,063	987,238
General and administrative expenses	59,744	59,740	73,110
Derivative (gain) loss	(4,199)	2,926	(14,375)
Total costs and expenses	377,146	730,554	1,652,968
Operating income (loss)	109,950	(330,568)	(1,145,703)
Interest expense:			
Incurred	45,836	92,791	104,592
Capitalized	—	(520)	(7,256)
Gain on exchange of debt	7,811	123,923	—
Other (income) expense, net	4,812	(6,520)	4,663
Income (loss) before income tax benefit	67,113	(292,396)	(1,247,702)
Income tax benefit	(12,569)	(43,376)	(202,984)
Net income (loss)	$ 79,682	$ (249,020)	$ (1,044,718)
Basic and diluted earnings (loss) per common share	$ 0.56	$ (2.60)	$ (13.76)

See accompanying notes.

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

	Common Stock Outstanding		Additional Paid-In	Retained Earnings	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	(Deficit)	Shares	Value	Equity (Deficit)
Balances at December 31, 2014	75,899	$ 1	$ 414,580	$ 118,894	2,869	$ (24,167)	$ 509,308
Share-based compensation	—	—	10,242	—	—	—	10,242
Stock issued	607	—	—	—	—	—	—
RSUs and shares surrendered for payroll taxes	—	—	(674)	—	—	—	(674)
Other	—	—	(649)	—	—	—	(649)
Net loss	—	—	—	(1,044,718)	—	—	(1,044,718)
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 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)

See accompanying notes.

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

	Year Ended December 31, 2017	2016	2015
Operating activities:			
Net income (loss)	$ 79,682	$ (249,020)	$ (1,044,718)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	155,682	211,609	394,071
Ceiling test write-down of oil and gas properties	—	279,063	987,238
Gain on exchange of debt	(7,811)	(123,923)	—
Debt issuance costs write-down/amortization of debt items	1,715	2,548	4,411
Share-based compensation	7,191	11,013	10,242
Derivative (gain) loss	(4,199)	2,926	(14,375)
Cash receipts on derivative settlements, net	4,199	4,746	6,703
Deferred income taxes	217	28,392	(203,272)
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(2,370)	(7,005)	32,236
Joint interest receivables	2,131	12	21,645
Insurance reimbursements	31,740	—	—
Income taxes	(1,063)	(64,274)	(7)
Prepaid expenses and other assets	3,238	(14,946)	17,816
Escrow deposit - Apache lawsuit	(49,500)	—	—
Asset retirement obligation settlements	(72,409)	(72,320)	(32,555)
Accounts payable, accrued liabilities and other	10,965	5,359	(46,207)
Net cash provided by operating activities	159,408	14,180	133,228
Investing activities:			
Investment in oil and natural gas properties and equipment	(130,048)	(48,606)	(230,161)
Changes in operating assets and liabilities associated with investing activities	23,874	(35,194)	(55,425)
Proceeds from sales of assets, net	—	1,500	372,939
Purchases of furniture, fixtures and other	(933)	(96)	(1,278)
Net cash provided by (used in) investing activities	(107,107)	(82,396)	86,075
Financing activities:			
Borrowings of long-term debt - revolving bank credit facility	—	340,000	263,000
Repayments of long-term debt - revolving bank credit facility	—	(340,000)	(710,000)
Issuance of 1.5 Lien Term Loan	—	75,000	—
Issuance of Second Lien Term Loan	—	—	297,000
Payment of interest on 1.5 Lien Term Loan	(8,227)	(2,570)	—
Payment of interest on 2nd Lien PIK Toggle Notes	(7,335)	—	—
Payment of interest on 3rd Lien PIK Toggle Notes	(6,201)	—	—
Debt exchange/issuance costs	(421)	(18,464)	(6,669)
Other	(1,295)	(928)	(886)
Net cash provided by (used in) financing activities	(23,479)	53,038	(157,555)
Increase (decrease) in cash and cash equivalents	28,822	(15,178)	61,748
Cash and cash equivalents, beginning of period	70,236	85,414	23,666
Cash and cash equivalents, end of period	$ 99,058	$ 70,236	$ 85,414

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. On October 15, 2015, a substantial amount of our interest in onshore acreage was sold, which is described in Note 7. 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 wholly-owned subsidiary, W & T Energy VI, LLC ("Energy VI").

Basis of Presentation

Our consolidated financial statements include the accounts of W&T Offshore, Inc. and its majority-owned subsidiaries. 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 2017 compared to the average realized prices in 2016. Operating costs were lower for 2017 on an absolute and on a per barrel oil equivalent ("Boe") basis compared to the operating costs for 2016.

In September 2016, we consummated the Exchange Transaction, as defined and described below in Note 2, which reduced our interest payments for 2017 as compared to 2016. In addition, the Exchange Transaction extended the maturities on a portion of our debt, although for a portion of the New Debt, as defined and described in Note 2, the maturities of two of the new loans will accelerate if certain events do not transpire.

We have continued working to further reduce our operating costs, capital expenditures and costs related to asset retirement obligations ("ARO"). Our capital expenditures incurred in 2017 were higher than the capital expenditures incurred during 2016, but were significantly lower than spending levels incurred during 2015 and prior years. Our current capital expenditure budget for 2018 is approximately the same level as incurred in 2017.

As of the filing date of this Form 10-K, the Company is in compliance with its financial assurance obligations to the Bureau of Ocean Energy Management ("BOEM") and has no outstanding BOEM orders related to financial assurance obligations.

During the second quarter of 2017, a trial court judgment was rendered in Apache Corporation's ("Apache") lawsuit against us. As a result, we deposited $49.5 million with the registry of the court from cash on hand as a first step to allow us to appeal the decision. See Note 17 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 March 2019, the period of assessment to qualify as a going concern. We are evaluating various alternatives and believe our plans can be executed in the current market and are within our capabilities. Our plans address the possible maturity acceleration of certain debt instruments, which could accelerate to February 28, 2019 if certain events were not to occur, and address events needed to extend our Credit Agreement, which matures on November 8, 2018. However, we cannot predict the potential changes in commodity prices or future bonding requirements, either of which could affect our operations, liquidity levels and compliance with debt obligations.

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 oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with joint ownership. Under this method, 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, 2017 and 2016, $4.7 million and $5.3 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,		
	2017	2016	2015
Customer			
Shell Trading (US) Co.	46%	43%	50%
Vitol Inc.	15%	20%	**
J. P. Morgan	**	**	14%

** 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:

	2017	2016	2015
Allowance for doubtful accounts, beginning of period	$ 7,602	$ 2,490	$ 704
Additional provisions for the year	1,512	5,112	1,786
Uncollectable accounts written off	—	—	—
Allowance for doubtful accounts, end of period	$ 9,114	$ 7,602	$ 2,490

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 5 for additional information.

Prepaid expenses and other

Amounts recorded in *Prepaid expenses and other* 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,	
	2017	2016
Prepaid/accrued insurance	$ 2,401	$ 2,924
Surety bonds unamortized premiums	2,676	2,462
Prepaid deposits related to royalties	6,456	6,237
Other	1,886	2,881
Prepaid expenses and other	$ 13,419	$ 14,504

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 equipment* 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 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,	
	2017	2016
Oil and natural gas properties and equipment	$ 8,102,044	$ 7,932,504
Furniture, fixtures and other	21,831	20,898
Total property and equipment	8,123,875	7,953,402
Less accumulated depreciation, depletion and amortization	7,544,859	7,406,349
Oil and natural gas properties and other, net	$ 579,016	$ 547,053

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 2017. We recorded ceiling test write-downs in 2016 and 2015, which are 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 were $279.1 million and $987.2 million for 2016 and 2015, respectively. If average crude oil and natural gas prices decrease from 2016 levels, it is possible that ceiling test write-downs could be recorded during 2018 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. For additional information, refer to Note 4.

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 21 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. 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 2017, no borrowings were outstanding on our revolving bank credit facility. We do not enter into derivative instruments for speculative trading purposes. We entered into commodity derivatives contracts during 2017, which were settled or expired during 2017. As of December 31, 2017 and 2016, we did not have any open derivative financial instruments.

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 commodity derivatives 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. We believe the carrying amount of debt under our 11.00% 1.5 Lien Term Loan, due November 2019, (the "1.5 Lien Term Loan") approximates fair value because of the debt's superior collateral ranking amongst our various debt instruments even though such debt was not traded.

Fair Value of Acquisitions

Acquisitions are recorded on the closing date of the transaction at their fair value, which is determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs are: (i) analysis of comparable transactions obtained from various third-parties, (ii) estimates of ultimate recoveries of reserves, and (iii) estimates of discounted cash flows based on estimated reserve quantities, reserve categories, timing of production, costs to produce and develop reserves, future prices, ARO and discount rates. The estimates and assumptions are determined by management and third-parties. The fair value is based on subjective estimates and assumptions, which are inherently imprecise, and the actual realized values can vary significantly from estimates that are made.

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 12 for additional information.

Other Assets (long-term)

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

	December 31, 2017	December 31, 2016
Escrow deposit - Apache lawsuit	$ 49,500	$ —
Appeal bond deposits	6,925	6,925
Investment in White Cap, LLC	2,511	2,520
Other	1,457	2,019
Total other assets	$ 60,393	$ 11,464

Accrued Liabilities

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

	December 31, 2017	December 31, 2016
Accrued interest	$ 4,200	$ 4,189
Accrued salaries/payroll taxes/benefits	2,454	2,777
Incentive compensation plans	7,366	—
Litigation accruals	3,480	1,891
Other	430	343
Total accrued liabilities	$ 17,930	$ 9,200

Troubled Debt Restructuring

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 New Debt (as defined in Note 2) is measured using all future undiscounted payments (principal and interest); therefore, no interest expense has been recorded for the newly issued debt in the Consolidated Statements of Operations since September 7, 2016. Additionally, no interest expense related to the New Debt will be recorded in future periods as payments of interest on this debt will be recorded as a reduction in the carrying amount; thus, our reported interest expense will be significantly less than the contractual interest payments beginning on September 7, 2016 and through the maturities of the New Debt. See Note 2 for additional information.

Debt Issuance Costs

Debt issuance costs associated with our revolving bank credit facility 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 revolving bank credit facility is reported within *Other Assets* (noncurrent) and unamortized debt issuance costs associated with our other debt is reported as a reduction in *Long-term debt, less current maturities* in the Consolidated Balance Sheets. See Note 2 for additional information.

Premiums Received and Discounts Provided on Debt Issuance

Premiums and discounts are recorded in *Long-term debt, less current maturities* in the Consolidated Balance Sheets and are amortized over the term of the related debt using the effective interest method.

Other Liabilities (long-term)

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

	December 31, 2017	December 31, 2016
Apache lawsuit	$ 49,500	$ —
Uncertain tax positions including interest/penalties	11,015	10,584
Other	6,351	6,521
Total other liabilities (long-term)	$ 66,866	$ 17,105

Share-Based Compensation

Compensation cost for share-based payments to employees and non-employee directors is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which the recipient is required to provide service in exchange for the award. The fair value for equity instruments subject to only time or to Company performance measures was determined using the closing price of the Company's common stock at the date of grant. We recognize share-based compensation expense on a straight line basis over the period during which the recipient is required to provide service in exchange for the award. Estimates are made for forfeitures during the vesting period, resulting in the recognition of compensation cost only for those awards that are estimated to vest and estimated forfeitures are adjusted to actual forfeitures when the equity instrument vests. See Note 10 for additional information.

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. For additional information, refer to Note 13.

Other (Income) Expense, Net

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 includes $7.7 million of income related to the settlement of certain insurance claims. In 2016 and 2015, the amount includes write-offs of debt issuance costs of $1.4 million and $3.2 million, respectively, related to a reduction in the borrowing base of the revolving bank credit facility under the Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement"). The write-offs of debt issuance costs in both 2016 and 2015 are included as an adjustment to net income in determining *Net cash provided by operating activities* in the Consolidated Statements of Cash Flows as the write-offs were non-cash transactions.

Recent Accounting Developments

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 is effective for annual and interim periods beginning after December 15, 2017. 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 is complete and we have 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, the implementation of ASU 2014-09 will not have a material impact on our consolidated financial statements. We will adopt ASU 2014-09 using the modified retrospective method that requires application of the new standard prospectively from the date of adoption with a cumulative effect adjustment, if any, recorded to retained earnings as of January 1, 2018 and revise our disclosures under ASU 2014-09 as applicable.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02 ("ASU 2016-02"), *Leases* (*Subtopic 842*). 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 finance or operating lease. However, unlike current GAAP, which requires only capital 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. Our current operating leases that will be impacted by ASU 2016-02 are leases for office space in Houston, Texas and New Orleans, Louisiana, although ASU 2016-02 may impact the accounting for leases related to equipment depending on the term of the lease. We currently do not have any leases classified as financing leases nor do we have any leases recorded on the Condensed Consolidated Balance Sheets. ASU 2016-02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective approach. We have not yet fully determined or quantified the effect ASU 2016-02 will have on our financial statements.

In June 2016, the FASB issued Accounting Standards Update No. 2016-13, ("ASU 2016-13"), *Financial Instruments – Credit Losses* (*Subtopic 326*). 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 2016, the FASB issued Accounting Standards Update No. 2016-15, ("ASU 2016-15"), *Statement of Cash Flows (Topic 230) – Classification of Certain Cash Receipts and Cash Payments*. ASU 2016-15 addresses the classification of several items that previously had diversity in practice. Items identified in the new standard which were incurred by us in the past are: (a) debt prepayment or extinguishment costs; (b) contingent consideration made after a business acquisition; and (c) proceeds from settlement of insurance claims. The item described in clause (b) would be the only such item changed under our historical classification in the statement of cash flows (financing vs. investing) and the amount of such change would not have been material; therefore, we do not anticipate the new standard will have a material effect on our financial statements. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017 and early adoption is permitted.

In November 2016, the FASB issued Accounting Standards Update No. 2016-18, ("ASU 2016-18"), *Statement of Cash Flows (Topic 230) – Restricted Cash*. ASU 2016-18 addresses diversity in practice and requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is expected to change some of the presentation in our statement of cash flows, but not materially impact total cash flows from operating, investing or financing activities. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period.

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

2. Long-Term Debt

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

	December 31, 2017			December 31, 2016		
	Principal	Adjustments to Carrying Value (1)	Carrying Value	Principal	Adjustments to Carrying Value (1)	Carrying Value
11.00% 1.5 Lien Term Loan, due November 2019:						
Principal	$ 75,000	$ —	$ 75,000	$ 75,000	$ —	$ 75,000
Future interest payments	—	15,596	15,596	—	23,823	23,823
Subtotal	75,000	15,596	90,596	75,000	23,823	98,823
9.00 % Second Lien Term Loan, due May 2020:	300,000	—	300,000	300,000	—	300,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020:						
Principal	171,769	—	171,769	163,007	—	163,007
Future payments-in-kind	—	5,745	5,745	—	24,048	24,048
Future interest payments	—	34,872	34,872	—	36,850	36,850
Subtotal	171,769	40,617	212,386	163,007	60,898	223,905
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021:						
Principal	153,192	—	153,192	145,897	—	145,897
Future payments-in-kind	—	11,323	11,323	—	26,844	26,844
Future interest payments	—	38,682	38,682	—	40,705	40,705
Subtotal	153,192	50,005	203,197	145,897	67,549	213,446
8.50% Unsecured Senior Notes, due June 2019	189,829	—	189,829	189,829	—	189,829
Debt premium, discount, issuance costs, net of amortization	—	(3,956)	(3,956)	—	(5,276)	(5,276)
Total long-term debt	889,790	102,262	992,052	873,733	146,994	1,020,727
Current maturities of long-term debt (2)	—	22,925	22,925	—	8,272	8,272
Long term debt, less current maturities	$ 889,790	$ 79,337	$ 969,127	$ 873,733	$ 138,722	$ 1,012,455

(1) Future interest payments and future payments-in-kind (“PIK”) are recorded on an undiscounted basis.
(2) Future interest payments on the 1.5 Lien Term Loan, Second Lien PIK Toggle Notes and Third Lien PIK Toggle Notes due within twelve months.

Aggregate annual maturities of amounts recorded for long-term debt as of December 31, 2017 are as follows (in millions): 2018–\$22.9; 2019–\$302.1; 2020–\$499.5; 2021–\$171.5. See below for a discussion of our debt instruments.

Exchange Transaction

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our 8.500% Senior Notes, due June 15, 2019 (the “Unsecured Senior Notes”), for: (i) $159.8 million in aggregate principal amount of 9.00%/10.75% Senior Second Lien PIK Toggle Notes, due May 15, 2020, (the “Second Lien PIK Toggle Notes”); (ii) $142.0 million in aggregate principal amount of 8.50%/10.00% Senior Third Lien PIK Toggle Notes, due June 15, 2021, (the “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, 11.00% 1.5 Lien Term Loan, due November 2019, 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 “New Debt”) is measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the New Debt in the Consolidated Statements of Operations since September 7, 2016. Additionally, no interest expense related to the New Debt will be recorded in future periods as payments of interest on the New Debt will be recorded as a reduction in the carrying amount; thus, our reported interest expense will be significantly less than the contractual interest payments through the maturities of the New Debt. Under ASC 470-60, payments related to the New 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 New 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.

The funds received from the 1.5 Lien Term Loan were used to pay transaction costs related to the Exchange Transaction and to pay down borrowings on the revolving bank credit facility. The balance of the borrowings on the revolving bank credit facility was paid down from available cash.

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 exchange of debt* in the Consolidated Statement of Operations. We anticipate the remaining eligible interest payments will be made in kind versus paid in cash. For 2017, $0.4 million of additional expense was recorded to *Gain on exchange of debt* 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.

The primary terms of our long-term debt following the Exchange Transaction are described below.

Credit Agreement

The Credit Agreement provides a revolving bank credit facility. Availability under the Credit Agreement is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. We and our lenders may request one additional determination per year. The borrowing base as of December 31, 2017 was $150.0 million. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. 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. Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists. The revolving bank credit facility is secured and is collateralized by a first priority lien on substantially all of our oil and natural gas properties. The Credit Agreement matures on November 8, 2018.

The Credit Agreement contains covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase our common stock or outstanding debt; (iii) sell our assets; (iv) make certain loans or investments; (v) merge or consolidate; (vi) eliminate certain hedging contracts or enter into certain hedging contracts in excess of 75% of projected oil and gas production on a monthly basis; (vii) enter into certain liens; and (viii) enter into certain other transactions, without the prior consent of the lenders. We are permitted to issue additional indebtedness if certain conditions are met including: (i) the additional debt is subordinate in security and right of payment; (ii) the borrowers enter into an intercreditor agreement with terms acceptable to the Administrative Agent of the Credit Agreement; (iii) we are in compliance with the financial covenants after giving pro forma effect to the additional indebtedness; and (iv) such additional unsecured indebtedness matures at least six months after the maturity date of the Credit Agreement and is not subject to restrictive covenants materially more onerous than those provided for in the Credit Agreement. With consent of the lenders, such limitation will not apply to the repurchase of our existing debt in an aggregate principal amount equal to or less than the aggregate principal amount of any new issuance of such debt. We are permitted to redeem, repurchase, prepay or defease up to $35 million of our Unsecured Senior Notes if after giving effect to such redemption, repayment, prepayment or defeasance: (i) no amounts are outstanding on the revolving bank credit facility; (ii) letters of credit outstanding do not exceed $5 million; (iii) the Consolidated Cash balance is at least $35 million after the redemption or repayment; and (iv) no event of default shall have occurred and be continuing, and no borrowing base deficiency shall have occurred and be continuing or result therefrom.

The Credit Agreement also contains various customary covenants for certain financial tests, as defined in the Credit Agreement and measured as of the end of each quarter, and for customary events of default. These financial test ratios and limits as of December 31, 2017 and thereafter are: (i) the First Lien Leverage Ratio must be less than 2.00 to 1.00; and (ii) the Current Ratio must be greater than 1.00 to 1.00. As of December 31, 2017, the Current Ratio was 2.80 to 1.00. As of December 31, 2017, the First Lien Leverage Ratio was in compliance, but not meaningful as no borrowings were outstanding on the revolving bank credit facility and only minor amounts of letters of credit were outstanding. The customary events of default include: (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) bankruptcy or insolvency with respect to the Company or any of its subsidiaries guaranteeing borrowings under the revolving bank credit facility; or (iii) a change of control. The Credit Agreement contains cross-default clauses with the other debt agreements, and these agreements contain similar cross-default clauses with the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2017.

We are required to have deposit accounts only with banks party to the Credit Agreement with certain exceptions. We may not have unrestricted cash balances above $35 million if outstanding balances on the revolving bank credit agreement (including letters of credit) are greater than $5 million.

Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate ("LIBOR") plus a margin that varies from 3.00% to 4.00% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the greater of (a) Prime Rate, (b) Federal Funds Rate plus 0.50%, or (c) LIBOR plus 1.0%, plus applicable margin ranging from 2.00% to 3.00%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%.

During 2016 and 2015, the borrowing base under the Credit Agreement was reduced. The reductions in the borrowing base resulted in proportional reductions in the unamortized costs related to the Credit Agreement of $1.4 million and $3.2 million in 2016 and 2015, respectively, which is included in the line *Other (income)/expense, net* on the Consolidated Statements of Operations.

At December 31, 2017 and 2016, we had no borrowings outstanding under the revolving bank credit facility. At December 31, 2017 and 2016, we had $0.3 million and $0.5 million, respectively, outstanding in letters of credit under the revolving bank credit facility.

1.5 Lien Term Loan

As part of the Exchange Transaction, we entered into the 1.5 Lien Term Loan on September 7, 2016 with a maturity date of November 15, 2019. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Certain amendments under the 1.5 Lien Term Loan and the Credit Agreement will likely be required in the event replacement financing is not utilized. Interest accrues at 11.00% per annum and is payable quarterly in cash. The holder of the 1.5 Lien Term Loan was the largest holder of our Unsecured Senior Notes prior to the Exchange Transaction. The 1.5 Lien Term Loan is secured by a 1.5 priority lien on all of our assets pledged under the Credit Agreement. The lien securing the 1.5 Lien Term Loan is subordinate to the liens securing the Credit Agreement and has priority above the liens securing the Second Lien Term Loan (defined below), the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes. All future undiscounted cash flows have been included in the carrying value under ASC 470-60. Current maturities of our long-term debt include the cash interest payable for the 1.5 Lien Term Loan payable in the next 12 months. The 1.5 Lien Term Loan contains various covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase our common stock; (iii) sell our assets; (iv) make certain loans or investments; (v) merge or consolidate; (vi) enter into certain liens; and (vii) enter into transactions with affiliates. We were in compliance with those covenants as of December 31, 2017.

Second Lien Term Loan

In May 2015, we entered into the 9.00% Term Loan (the "Second Lien Term Loan"), which bears an annual interest rate of 9.00%. The Second Lien Loan was issued at a 1.0% discount to par, matures on May 15, 2020 and is recorded at its carrying value consisting of principal, unamortized discount and unamortized debt issuance costs. Interest on the Second Lien Term Loan is payable in arrears semi-annually on May 15 and November 15. The estimated annual effective interest rate on the Second Lien Term Loan is 9.6%, which includes amortization of debt issuance costs and discounts. The Second Lien Term Loan is secured by a second-priority lien on all of our assets that are secured under the Credit Agreement. The Second Lien Term Loan is effectively subordinate to the Credit Agreement and the 1.5 Lien Term Loan (discussed above) and is effectively *pari passu* with the Second Lien PIK Toggle Notes (discussed below). The Second Lien Term Loan contains covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of December 31, 2017.

Second Lien PIK Toggle Notes

As part of the Exchange Transaction, we issued Second Lien PIK Toggle Notes on September 7, 2016, with a maturity date of May 15, 2020. Cash interest accrues at 9.00% per annum and is payable on May 15 and November 15 of each year. The Second Lien PIK Toggle Notes contain payment-in-kind interest provisions, where certain semi-annual interest is added to the principal amount instead of being paid in cash in the then current semi-annual period. This payment-in-kind provision expires on March 7, 2018. For the initial interest payment on November 15, 2016, interest could only be paid-in-kind at 10.75% per annum. For the six month interest period ending May 15, 2017, we paid the interest payment in cash rather than using the payment-in-kind provision. For the six-month period ended November 15, 2017, we exercised the payment-in-kind provision. For the interest period ending May 15, 2018, we have exercised the payment-in-kind provision to pay interest through March 7, 2018, and, thereafter, interest will be paid in cash. When the PIK option is utilized, the principal amount of the notes increases. The Second Lien PIK Toggle Notes are secured by a second-priority lien on all of our assets that are pledged under the Credit Agreement. The Second Lien PIK Toggle Notes are effectively subordinate to the Credit Agreement and the 1.5 Lien Term Loan (discussed above) and are effectively *pari passu* with the Second Lien Term Loan (discussed above). Current maturities of long-term debt as of December 31, 2017 include the cash interest payable for the Second Lien PIK Toggle Notes for the next 12 months. The Second Lien PIK Toggle Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of December 31, 2017.

Third Lien PIK Toggle Notes

As part of the Exchange Transaction, we issued Third Lien PIK Toggle Notes on September 7, 2016, with a maturity date of June 15, 2021. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Certain amendments under the 1.5 Lien Term Loan and the Credit Agreement will likely be required in the event replacement financing is not utilized. Cash interest accrues at 8.50% per annum and is payable on June 15 and December 15 of each year. The Third Lien PIK Toggle Notes contain PIK interest provisions, where certain semi-annual interest is added to the principal amount instead of being paid in cash in the then current semi-annual period. This payment-in-kind provision expires on September 7, 2018. For the initial interest payment on December 15, 2016, interest could only be paid-in-kind at 10.00% per annum. For the six month interest period ending June 15, 2017, we paid the interest payment in cash rather than using the payment-in-kind provision. For the six-month period ended November 15, 2017, we exercised the payment-in-kind provision. For the six-month period ended June 15, 2018, we have exercised the payment-in-kind provision. When the PIK option is utilized, the principal amount of the notes increases. The Third Lien PIK Toggle Notes are secured by a third-priority lien on all of our assets that are secured under the Credit Agreement. The Third Lien PIK Toggle Notes are effectively subordinate to the Second Lien Term Loan and the Second Lien PIK Toggle Notes. For purposes of determining the carrying amount under ASC 470-60, we anticipate the remaining eligible interest payments will be paid-in-kind versus paid in cash. The Third Lien PIK Toggle Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of December 31, 2017.

Unsecured Senior Notes

At December 31, 2017 and 2016, our outstanding Unsecured Senior Notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019, were classified as long-term at their carrying value. The Unsecured Senior Notes are currently redeemable at par. Subject to limited exceptions, our 1.5 Lien Term Loan and Credit Agreement restrict us from using cash on hand to repay or repurchase our Unsecured Senior Notes prior to their stated maturity, although we can generally refinance our Unsecured Senior Notes with new indebtedness within customary parameters. Certain amendments under the 1.5 Lien Term Loan and the Credit Agreement will likely be required in the event replacement financing is not utilized. Interest on the Unsecured Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the Unsecured Senior Notes is 8.3%, which includes amortization of debt issuance costs and premiums. The Unsecured Senior Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with all applicable covenants as of December 31, 2017.

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

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 long-term debt (in thousands):

		December 31,	
	Hierarchy	2017	2016
11.00% 1.5 Lien Term Loan, due November 2019	Level 2	$ 75,000	$ 75,000
9.00 % Second Lien Term Loan, due May 2020	Level 2	288,000	255,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020	Level 2	162,322	122,255
8.50%/10.00% Third Lien PIK Toggle Notes due June 2021	Level 2	119,490	80,243
8.50% Unsecured Senior Notes, due June 2019	Level 2	178,439	123,389

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. An exception is the fair value of the 1.5 Lien Term Loan, which is held by one entity, and has not traded since its inception in September 2016. We believe the carrying amount of debt under our 1.5 Lien Term Loan approximates fair value because of the debt's superior collateral ranking amongst our debt instruments even though such debt was not traded. Given the relatively short time until maturity, having an interest rate higher than any our other debt instruments and having superior collateral ranking over our other debt instruments, we assessed the fair value of the 1.5 Lien Term Loan to be at least equivalent to its carrying value.

As of December 31, 2017 and 2016, there were no open derivatives financial instruments.

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

4. 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,	
	2017	2016
Asset retirement obligations, beginning of period	$ 334,438	$ 378,322
Liabilities settled	(72,409)	(72,320)
Accretion of discount	17,172	17,571
Liabilities incurred	163	398
Revisions of estimated liabilities	21,082	10,467
Asset retirement obligations, end of period	300,446	334,438
Less current portion	23,613	78,264
Long-term	$ 276,833	$ 256,174

During 2017, we decreased our ARO liability on an overall basis primarily due to plug and abandonment work performed during 2017, partially offset by increases from accretion and revisions of previous estimates. Revisions 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.

During 2016, we decreased our ARO liability on an overall basis primarily due to plug and abandonment work performed during 2016, partially offset by increases from accretion and revisions of previous estimates. Upward revisions were primarily related to sustained casing pressure issues at our West Cameron fields identified while performing preliminary plug and abandonment work at these fields. In addition, increases were attributable to several non-operated properties under which we have no control. Partially offsetting are downward revisions to cost estimates from service providers for plug and abandonment work at certain locations.

5. 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.

For 2017, 2016 and 2015, we received insurance reimbursements of $31.7 million, $10.2 million and $0.2 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 equipment* 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, 2017, we have received $203.1 million cumulative reimbursements from insurance companies related to hurricane reimbursements. As of December 31, 2017, there were no outstanding hurricane claims.

6. Restricted Deposits

Restricted deposits as of December 31, 2017 and 2016 consisted of funds escrowed for collateral related to the future plugging and abandonment obligations of certain oil and natural gas properties.

Pursuant to the Purchase and Sale Agreement with Total E&P USA Inc. ("Total E&P"), security for future plugging and abandonment of certain oil and natural gas properties is required either through surety bonds or payments to an escrow account or a combination thereof. Monthly payments are made to an escrow account and these funds are returned to us once verification is made that the security amount requirements have been met. See Note 15 for potential future security requirements.

7. Divestitures

2015 Divestiture

On October 15, 2015, we sold certain onshore oil and natural gas property interests to Ajax Resources, LLC ("Ajax") for approximately $370.9 million in cash, which includes certain customary price adjustments, and Ajax assumed responsibility for the related ARO. The effective date of the sale was January 1, 2015. A net purchase price adjustment of $0.9 million for final customary effective date adjustments was recorded during 2016. Ajax acquired all of our interest in the Yellow Rose field in the Permian Basin, covering approximately 25,800 net acres in Andrews, Martin, Gaines and Dawson counties in West Texas. We retained a non-expense bearing overriding royalty interest ("ORRI") equal to a variable percentage in production from the working interests assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the prompt month New York Mercantile Exchange ("NYMEX") trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel. We used a portion of the proceeds of the sale to repay all outstanding borrowings under the revolving bank credit facility, while the remaining balance of approximately $100.0 million was added to available cash.

Under the full-cost method, sales or abandonments of oil and natural gas properties, whether or not being amortized, 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 attributable to the cost center. The sale to Ajax did not represent greater than 25% of our proved reserves of oil and natural gas attributable to the full cost pool. As a result, alteration in the relationship between capitalized costs and proved reserves of oil and natural gas attributable to the full cost pool was not deemed significant and no gain or loss was recognized from the sale.

8. 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. All of the derivative counterparties are also lenders or affiliates of lenders participating in our revolving bank credit facility. 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 is not required by us due to the derivative counterparties' collateral rights as lenders, 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

As of December 31, 2017 and 2016, we did not have any open derivative contracts. During 2017, we entered into crude oil and natural gas derivative contracts for a portion of our anticipated future production. Some of the commodity derivative contracts are known as "three-way collars" consisting of a purchased put option, a sold call option and a purchased call option, each at varying strike prices. The strike prices of the contracts were set so that the contracts were premium neutral ("costless"), which means no net premium was paid to or received from a counterparty. The three-way collar contracts are structured to provide price risk protection if the commodity price falls below the strike price of the put option and provides us the opportunity to benefit if the commodity price rises above the strike price of the purchased call option. In addition, we entered into oil derivative contracts known as "two-way", "costless" collars, which consist of a purchased put option and a sold call option. These two-way collars provide price risk protection if crude oil prices fall below certain levels, but have the potential to limit incremental income from favorable price movements above certain limits. The oil contracts are based on West Texas Intermediate ("WTI") crude oil prices as quoted off the NYMEX. The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX.

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

	Year Ended December 31,		
	2017	**2016**	**2015**
Derivative (gain) loss	$ (4,199)	$ 2,926	$ (14,375)

Cash receipts (payments), net, on commodity derivative contract settlements 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,		
	2017	**2016**	**2015**
Cash receipts on derivative settlements, net	$ 4,199	$ 4,746	$ 6,703

9. 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 2017, 2016 and 2015, we did not pay any dividends and dividends are currently suspended.

10. Share-Based Awards and Cash-Based Awards

Incentive Compensation Plan

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our shareholders. During 2017, 2016, and 2013, amendments to the Plan were approved by our shareholders. The Plan covers the Company's eligible employees and consultants. In addition to other cash and share-based compensation awards, the Plan has historically been designed to grant awards that qualified as performance-based compensation within the meaning of section 162(m) of the Internal Revenue Code ("IRC"). Beginning in 2018, IRC section 162(m) will no longer contain deduction exemptions for performance-based compensation except for plans in place prior to November 2, 2017 that meet certain certifications. 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.

The 2017 amendment increased the number of shares available in the Plan by 7,700,000 shares of common stock. As of December 31, 2017, there were 13,363,792 shares of common stock available for issuance in satisfaction of awards under the Plan. RSUs reduce the shares available in the Plan when settled in shares of common stock, net of withholding tax.

Share-based Awards: Restricted Stock Units

For 2017, 2016 and 2015, performance awards under the Plan were granted in the form of RSUs to eligible employees. As defined by the Plan, RSUs are rights to receive stock, cash or a combination thereof at the end of a specified vesting period, subject to certain terms and conditions as determined by the Committee. RSUs are a long-term compensation component of the Plan, which are granted to only certain employees, and are subject to adjustments at the end of the applicable performance period using a predefined scale based on the Company achieving certain predetermined performance criteria. Vesting occurs upon completion of the specified vesting period applicable to each grant. Subsequent to the determination of the performance achievement and prior to vesting, the RSUs earn dividend equivalents at the same rate as dividends paid on our common stock. RSUs are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period.

During 2017, 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 2017 and (ii) Adjusted EBITDA as a percent of total revenue ("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 and 2015, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA and (ii) Adjusted EBITDA Margin for each respective year. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For both 2016 and 2015, the Company was below target for Adjusted EBITDA and achieved target for Adjusted EBITDA Margin.

All RSUs granted to date are subject to employment-based criteria in addition to performance criteria. Vesting occurs in December of the second calendar year following the date of grant. For example, the RSUs granted during 2015 (after adjustment for performance) vested in December 2017 to eligible employees. The Company has the option to settle RSUs in stock or cash at vesting. Prior to 2017, only shares of common stock were used to settle 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 plans to settle RSUs that vest in the future using shares of common stock.

During 2017, 2016 and 2015, the Company granted RSUs to certain employees, with nearly all grants being contingent upon meeting specified performance requirements described above. The fair value of the RSUs granted for all years presented was determined using the Company's closing price on the grant dates.

A summary of activity related to RSUs is as follows:

	2017		2016		2015	
	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	6,107,248	$ 2.73	3,474,079	$ 7.42	1,977,335	$ 15.29
Granted	2,128,879	2.76	4,213,964	2.21	2,626,930	3.59
Vested	(2,108,553)	3.45	(968,652)	16.69	(721,038)	13.23
Forfeited	(362,323)	2.87	(612,143)	3.64	(409,148)	10.63
Nonvested, end of period	5,765,251	$ 2.48	6,107,248	$ 2.73	3,474,079	$ 7.42

Subject to the satisfaction of service conditions, the RSUs outstanding as of December 31, 2017 are eligible to vest in the year indicated in the table below:

	Restricted Stock Units
2018	3,742,509
2019	2,022,742
Total	5,765,251

RSUs fair value at grant date - During 2017, 2016 and 2015, the grant date fair value of RSUs granted was $5.9 million, $9.3 million and $9.4 million, respectively.

RSUs fair value at vested date - The fair value of the RSUs that vested during 2017, 2016 and 2015 was $5.5 million, $2.4 million and $2.1 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 2017, 2016 and 2015 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, 2017, there were 170,524 shares of common stock available for issuance in satisfaction of awards under the Directors Compensation Plan. Reductions in shares available are made when Restricted Shares are granted.

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

	2017		2016		2015	
	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	161,296	$ 3.47	78,230	$ 8.95	43,210	$ 16.20
Granted	147,372	1.90	126,128	2.22	56,540	6.19
Vested	(62,140)	4.51	(43,062)	9.75	(21,520)	16.26
Nonvested, end of period	246,528	$ 2.27	161,296	$ 3.47	78,230	$ 8.95

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2017 are expected to vest as follows:

	Restricted Shares
2018	106,240
2019	91,164
2020	49,124
Total	246,528

Restricted stock fair value at grant date - The grant date fair value of restricted stock granted during 2017, 2016 and 2015 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 2017, 2016 and 2015 was $0.1 million each year for all years presented 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,		
	2017	2016	2015
Share-based compensation expense from:			
Restricted stock units	$ 7,785	$ 10,640	$ 9,978
Restricted stock	280	373	358
Common shares	—	—	(94)
Total	$ 8,065	$ 11,013	$ 10,242
Share-based compensation tax benefit:			
Tax benefit computed at the statutory rate	$ 1,694	$ 3,855	$ 3,585

As of December 31, 2017, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $6.2 million and $0.4 million, respectively. Unrecognized compensation expense will be recognized through November 2019 for our RSUs and April 2020 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 2017, 2016 and 2015. 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 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 for the 2017 cash-based awards. Payments are expected to be made in March 2018 and are subject to all the terms of the 2017 Annual Incentive Award Agreement.

- 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 as of December 31, 2017; therefore no expense was recognized during 2017 or 2016. The terms of the 2016 cash-based awards allow for the measurement of the financial condition to be made up through December 31, 2018. If the financial condition is achieved, payment is to be made within 30 days of achievement of the financial condition.

- For the 2015 cash-based awards, the financial condition was not achieved through the measurement date; therefore, all awards granted were forfeited and no expense was recognized in any of the reported periods.

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,		
	2017	2016	2015
Share-based compensation included in:			
General and administrative	$ 8,065	$ 11,013	$ 10,242
Cash-based incentive compensation included in:			
Lease operating expense	2,101	—	364
General and administrative [1]	5,032	—	(233)
Total charged to operating income	$ 15,198	$ 11,013	$ 10,373

(1) Adjustments to true up estimates to actual payments resulted in net credit balances to expense in 2015

11. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the IRC (the "401(k) Plan"), 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 $1.4 million, $0.4 million and $2.3 million for 2017, 2016 and 2015, respectively.

12. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2017	2016	2015
Current	$ (12,786)	$ (71,768)	$ 288
Deferred	217	28,392	(203,272)
Total income tax (benefit)	$ (12,569)	$ (43,376)	$ (202,984)

Effective Tax Rate Reconciliation

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

	Year Ended December 31,					
	2017		2016		2015	
Income tax (benefit) at the federal statutory rate	$ 23,490	35.0 %	$ (102,339)	35.0 %	$ (436,696)	35.0 %
Share-based compensation	664	1.0	4,920	(1.7)	2,940	(0.2)
State income taxes	63	0.1	(755)	0.2	(2,343)	0.2
Debt restructuring cost	18	—	1,463	(0.5)	—	—
Change in statutory federal tax rate	105,933	157.8	—	—	—	—
Gain on exchange of debt	(24,981)	(37.2)	—	—	—	—
Valuation allowance	(118,643)	(176.8)	52,915	(18.1)	232,925	(18.7)
Other	887	1.4	420	(0.1)	190	—
Total income tax (benefit)	$ (12,569)	(18.7 %)	$ (43,376)	14.8 %	$ (202,984)	16.3 %

Our effective tax rate for the years 2017, 2016 and 2015 differed from the federal statutory rate of 35.0% 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,	
	2017	2016
Deferred tax liabilities:		
Other	$ 695	$ 1,423
Total deferred tax liabilities	695	1,423
Deferred tax assets:		
Property and equipment	18,234	42,385
Asset retirement obligations	63,755	117,588
Federal net operating losses	18,988	—
State net operating losses	7,126	5,615
Exchange transaction	55,807	118,467
Share-based compensation	1,335	2,353
Valuation allowance	(171,547)	(290,190)
Other	6,805	4,798
Total deferred tax assets	503	1,016
Net deferred tax assets (liabilities)	$ (192)	$ (407)

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 refundsand made income tax payments of $0.3 million. The refunds received in 2017 and 2016 were primarily due to net operating loss ("NOL") carryback claims made pursuant to IRC Section 172 (f) (related to rules of "specified liability losses"). During 2015, we did not make any payments for federal or state income taxes or receive any refunds of significance.

Income Taxes Receivables

As of December 31, 2017, we have recorded a current income taxes receivable of $13.0 million and a non-current income taxes receivable of $52.1 million.The current income taxes receivable primarily relate to a net operating loss carried back claim for 2017. The non-current income taxes receivable relates to our NOL claims for the years 2012, 2013 and 2014 that were carried back to prior years. These carryback claims are 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 and are accordingly classified as non-current.

Net Operating Loss and Tax Credit Carryovers

The table below presents the details of our net operating loss and tax credit carryovers as of December 31, 2017 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 18,988	2037
State net operating losses	118,027	2025-2036

Valuation Allowance

During 2017, we recorded a decrease in the valuation allowance of $118.6 million and in 2016, we recorded an increase in the valuation allowance of $52.9 million related to federal and state deferred tax assets. As a result of the enactment of the Tax Cuts and Jobs Act ("TCJA"), on December 22, 2017, our net deferred tax assets and its respective valuation allowance were provisionally adjusted downwards by $105.9 million as of December 31, 2017. 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, 2017 and 2016, we had a valuation allowance related to our federal and state deferred tax assets. Due to the timing and the complexity involved in applying the provisions of the TCJA, our application of the TCJA may require further adjustments during 2018 in the determination of the final effects in our financial statements.

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. There are no unrecognized benefits that would impact the effective tax rate if recognized. While amounts could change in the next 12 months, we do not anticipate it having a material impact on our financial statements.

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

	December 31,	
	2017	2016
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 2017, 2016 and 2015, the amounts recognized in income tax expense were immaterial.

Years open to examination

The tax years from 2013 through 2017 remain open to examination by the tax jurisdictions to which we are subject.

13. 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, 2017	2016	2015
Net income (loss)	$ 79,682	$ (249,020)	$ (1,044,718)
Less portion allocated to nonvested shares	3,244	—	—
Net income (loss) allocated to common shares	$ 76,438	$ (249,020)	$ (1,044,718)
Weighted average common shares outstanding	137,617	95,644	75,931
Basic and diluted earnings (loss) per common share	$ 0.56	$ (2.60)	$ (13.76)
Shares excluded due to being anti-dilutive (weighted-average)	—	5,269	2,195

14. Supplemental Cash Flow Information

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

	Year Ended December 31, 2017	2016	2015
Supplemental cash items:			
Cash paid for interest, net of interest capitalized of $0 in 2017, $520 in 2016 and $7,256 in 2015 (1)	$ 65,873	$ 96,501	$ 92,622
Cash paid for income taxes	185	310	390
Cash refunds received for income taxes	11,906	7,796	90
Cash paid for share-based compensation (2)	874	—	—
Non-cash investing activities:			
Accruals of property and equipment	33,003	9,129	44,324
ARO - additions, dispositions and revisions, net	21,245	10,865	(394)
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 2017 and 2016, cash paid for interest included amounts related to the New Debt, which are accounted for under ASC 470-60 and recorded against the carrying value of the New Debt instruments on the Consolidated Balance Sheets and included in *financing activities* on the Consolidated Statements of Cash Flows.

(2) 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 and to settle restricted stock. During 2016 and 2015, only common shares were used to settle vested RSUs and Restrict stock.

15. Commitments

We have operating lease agreements for office space and office equipment. The lease for the majority of 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, 2017 are as follows: 2018–$1.8 million; 2019–$1.8 million; 2020–$1.8 million; 2021–$1.8 million thereafter–$2.0 million. Total rent expense was approximately $3.0 million, $3.2 million and $3.3 million during 2017, 2016 and 2015, 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 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, 2017, we had bonds related to the agreement with Total E&P totaling $81.3 million and had no amounts in escrow. The threshold is $88.0 million for 2018, $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 bonds that are subject to re-appraisal by either party. As of December 31, 2017, neither party had requested a re-appraisal to be made. The current security requirement of $64.0 million could be increased up to $94.0 million depending on certain conditions and circumstances.

During 2017, 2016 and 2015, 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 $5.7 million, $4.3 million and $5.5 million during 2017, 2016 and 2015, 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 2030. Future costs are estimated as follows: 2018–$6.2 million; 2019–$6.0 million; 2020–$5.7 million; 2021–$5.3 million; thereafter–$42.4 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, 2017, we had $16.9 million of collateral deposits for certain sureties related to certain surety bonds for decommissioning obligations and appeals submitted to the Interior Board of Land Appeals (the “IBLA”).

Pursuant to an agreement with the Helix Well Containment Group, we are required to make payments quarterly in advance to have access to certain equipment to respond to a subsea spill should a spill occur at a property we operate. As of December 31, 2017, our commitment is $1.5 million for 2018. These payments may increase or decrease depending on whether the number of companies participating in the consortium changes.

We have no drilling rig commitments with a term that exceeded one year as of December 31, 2017 and our drilling rig commitments meet the criteria of an operating lease. Future payments of all drilling rig commitments as of December 31, 2017 were $5.7 million.

16. Related Parties

During 2017, 2016 and 2015, 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 were charged to us at rates that were either equal to or below rates charged by non-related, third-party companies. Airplane services transactions were approximately $1.2 million, $1.1 million and $1.1 million for the years 2017, 2016 and 2015, 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 $22.8 million in 2017. The spouse received commissions partially based on services rendered to W&T which were approximately $0.2 million 2017 and less than $0.2 million for both 2016 and 2015. During 2015, an entity controlled by our CEO participated in the Second Lien Term Loan for a $5.0 million principal commitment on the same terms as the other lenders.

17. Contingencies

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 2017.

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 (“MC”) 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. 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.

The dispute relates to Apache's use of drilling rigs instead of a previously contracted intervention vessel for the plugging and abandonment work. We contended that the costs to use the drilling rigs were unnecessary and unreasonable, and that Apache chose to use the rigs without W&T's consent because they otherwise would have been idle at Apache's expense. We believe the use of the rigs was in bad faith, as found by the jury, and that such conduct caused W&T not to comply with the applicable joint operating agreement, particularly since another vessel had been contracted by Apache for the abandonment a year in advance. We had previously paid $24.9 million to Apache as an undisputed amount for the plug and abandonment work.

On October 28, 2016, the jury made the following findings:

1. W&T failed to comply with the contract by failing to pay its proportionate share of the costs to plug and abandon the MC 674 wells.
2. The amount of money to compensate Apache for W&T’s failure to pay its proportionate share of the costs to plug and abandon the MC 674 wells was $43.2 million.
3. The $43.2 million referred to in #2 should be offset by $17.0 million.
4. Apache acted in bad faith thereby causing W&T to not comply with the contract.

The deposit of $49.5 million with the registry of the court is recorded in *Other assets* (long-term) with a corresponding reduction to Cash and cash equivalents on the Consolidated Balance Sheet as of December 31, 2017. Although we are appealing the decision, based solely on the decision rendered, we have 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 as of December 31, 2017 and have recognized $6.3 million of expense included in *Other (income) expense, net* on the Consolidated Statement of Operations for 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 an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana.

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 2017 and 2016, we paid $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.

Notices of Proposed Civil Penalty Assessment

During 2017 and 2016, we paid $0.2 million and $0.1 million, respectively, of civil penalties to the BSEE related to Incidents of Noncompliance ("INCs") issued by the BSEE at various offshore locations. We currently have four 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 INC's underlying the civil penalties were issued during 2015, with one re-issued during 2016, and relate to four separate offshore locations with occurrence dates ranging from July 2012 to June 2014. The proposed civil penalties for these INCs total $7.3 million. We have accrued approximately $3.3 million, 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.

18. Selected Quarterly Financial Data—UNAUDITED

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2017				
Revenues	$ 124,393	$ 123,323	$ 110,281	$ 129,099
Operating income	28,196	32,888	15,700	33,166
Net income (loss)	24,299	33,315	(1,297)	23,365
Basic and diluted earnings (loss) per common share	0.17	0.23	(0.01)	0.16
Year Ended December 31, 2016				
Revenues	$ 77,715	$ 99,655	$ 107,403	$ 115,213
Operating income (loss) (1)	(166,614)	(126,997)	(58,276)	21,319
Net income (loss) (1)	(190,509)	(120,922)	45,928	16,483
Basic and diluted earnings (loss) per common share (1) (2)	(2.49)	(1.58)	0.48	0.12

(1) During 2016, we recorded in first, second and third quarter ceiling test write-downs of oil and natural gas properties of $116.6 million, $104.6 million and $57.9 million, respectively. In the third quarter of 2016, we recorded a gain on exchange of debt of $123.9 million. See Note 1 and Note 2 for additional information.

(2) The sum of the individual quarterly earnings (loss) per share does not agree with the year loss per share because each quarterly calculation is based on the income for that quarter and the weighted average number of shares outstanding during that quarter. During the third quarter of 2016, 60.4 million shares of common stock were issued in conjunction with the Exchange Transaction.

19. Supplemental Guarantor Information

Our payment obligations under the Credit Agreement, the 1.5 Lien Term Loan, the Second Lien Term Loan, the Second Lien PIK Toggle Notes, the Third Lien PIK Toggle Notes and the Unsecured Senior Notes (see Note 2) are fully and unconditionally guaranteed by certain of our 100%-owned subsidiaries, W & T Energy VI and W & T Energy VII, LLC (together, the "Guarantor Subsidiaries"). W & T Energy VII, LLC does not currently have any active operations or any assets. Guarantees will be released under certain circumstances, including:

(1) in connection with any sale or other disposition of all or substantially all of the assets of a Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary, if the sale or other disposition does not violate the Asset Sale provisions (as such capitalized terms are defined in the applicable indenture);

(2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the Asset Sale provisions of the indenture and the Guarantor Subsidiary ceases to be a subsidiary of the Company as a result of such sales or disposition;

(3) if such Guarantor Subsidiary is a Restricted Subsidiary and the Company designates such Guarantor Subsidiary as an Unrestricted Subsidiary in accordance with the applicable provisions of certain debt documents;

(4) upon Legal Defeasance or Covenant Defeasance (as such terms are defined in the applicable indenture) or upon satisfaction and discharge of the certain debt documents;

(5) upon the liquidation or dissolution of such Guarantor Subsidiary, provided no event of default has occurred and is continuing; or

(6) at such time as such Guarantor Subsidiary is no longer required to be a Guarantor Subsidiary as described in certain debt documents, provided no event of default has occurred and is continuing.

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of the Parent Company and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. As to the ceiling test write-downs recorded in 2016 and 2015, the computation is performed for each subsidiary on a stand-alone basis and also for the consolidated Company. Due to this methodology, consolidating adjustments are required to present the consolidated results appropriately.

Condensed Consolidating Balance Sheet as of December 31, 2017
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	$ 99,058	$ —	$ —	$ 99,058
Receivables:				
Oil and natural gas sales	5,665	39,778	—	45,443
Joint interest	19,754	—	—	19,754
Income taxes	128,835	—	(115,829)	13,006
Total receivables	154,254	39,778	(115,829)	78,203
Prepaid expenses and other assets	11,154	2,265	—	13,419
Total current assets	264,466	42,043	(115,829)	190,680
Oil and natural gas properties and other, net - at cost:	430,354	152,464	(3,802)	579,016
Restricted deposits for asset retirement obligations	25,394	—	—	25,394
Income tax receivables	52,097	—	—	52,097
Other assets	505,304	453,306	(898,217)	60,393
Total assets	$ 1,277,615	$ 647,813	$ (1,017,848)	$ 907,580
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities:				
Accounts payable	$ 76,703	$ 6,962	$ —	$ 83,665
Undistributed oil and natural gas proceeds	18,762	1,367	—	20,129
Asset retirement obligations	22,488	1,125	—	23,613
Long-term debt	22,925	—	—	22,925
Accrued liabilities	18,058	115,701	(115,829)	17,930
Total current liabilities	158,936	125,155	(115,829)	168,262
Long-term debt:				
Principal	889,790	—	—	889,790
Carrying value adjustments	79,337	—	—	79,337
Long term debt, less current portion - carrying value	969,127	—	—	969,127
Asset retirement obligations, less current portion	152,883	123,950	—	276,833
Other liabilities	566,375	—	(499,509)	66,866
Shareholders' equity (deficit):				
Common stock	1	—	—	1
Additional paid-in capital	545,820	704,885	(704,885)	545,820
Retained earnings (deficit)	(1,091,360)	(306,177)	302,375	(1,095,162)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(569,706)	398,708	(402,510)	(573,508)
Total liabilities and shareholders' equity (deficit)	$ 1,277,615	$ 647,813	$ (1,017,848)	$ 907,580

Condensed Consolidating Balance Sheet as of December 31, 2016
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	$ 70,236	$ —	$ —	$ 70,236
Receivables:				
Oil and natural gas sales	2,173	40,900	—	43,073
Joint interest	21,885	—		21,885
Insurance reimbursement	30,100	—	—	30,100
Income taxes	111,215	—	(99,272)	11,943
Total receivables	165,373	40,900	(99,272)	107,001
Prepaid expenses and other assets	12,448	2,056	—	14,504
Total current assets	248,057	42,956	(99,272)	191,741
Oil and natural gas properties and other, net	360,966	187,040	(953)	547,053
Restricted deposits for asset retirement obligations	27,371	—	—	27,371
Income tax receivables	52,097	—	—	52,097
Other assets	394,931	344,742	(728,209)	11,464
Total assets	$ 1,083,422	$ 574,738	$ (828,434)	$ 829,726
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities:				
Accounts payable	$ 74,306	$ 6,733	$ —	$ 81,039
Undistributed oil and natural gas proceeds	24,493	1,761	—	26,254
Asset retirement obligations	62,261	16,003	—	78,264
Long-term debt	8,272	—	—	8,272
Accrued liabilities	9,293	99,179	(99,272)	9,200
Total current liabilities	178,625	123,676	(99,272)	203,029
Long-term debt:				
Principal	873,733	—	—	873,733
Carrying value adjustments	138,722	—	—	138,722
Long term debt, less current portion - carrying value	1,012,455	—	—	1,012,455
Asset retirement obligations, less current portion	142,376	113,798	—	256,174
Other liabilities	408,050	—	(390,945)	17,105
Shareholders' equity (deficit):				
Common stock	1	—	—	1
Additional paid-in capital	539,973	704,885	(704,885)	539,973
Retained earnings (deficit)	(1,173,891)	(367,621)	366,668	(1,174,844)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(658,084)	337,264	(338,217)	(659,037)
Total liabilities and shareholders' equity (deficit)	$ 1,083,422	$ 574,738	$ (828,434)	$ 829,726

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2017
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Revenues	$ 231,396	$ 255,700	$ —	$ 487,096
Operating costs and expenses:				
Lease operating expenses	79,695	64,043	—	143,738
Production taxes	1,740	—	—	1,740
Gathering and transportation	9,781	10,660	—	20,441
Depreciation, depletion and amortization	73,962	61,700	2,848	138,510
Asset retirement obligations accretion	7,416	9,756	—	17,172
General and administrative expenses	28,170	31,574	—	59,744
Derivative gain	(4,199)	—	—	(4,199)
Total costs and expenses	196,565	177,733	2,848	377,146
Operating Income	34,831	77,967	(2,848)	109,950
Earnings of affiliates	61,444	—	(61,444)	—
Interest expense incurred	45,836	—	—	45,836
Gain on exchange of debt	7,811	—	—	7,811
Other expense, net	4,812	—	—	4,812
Income before income tax expense (benefit)	53,438	77,967	(64,292)	67,113
Income tax expense (benefit)	(29,092)	16,523	—	(12,569)
Net income	$ 82,530	$ 61,444	$ (64,292)	$ 79,682

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2016
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Revenues	$ 161,063	$ 238,923	$ —	$ 399,986
Operating costs and expenses:				
Lease operating expenses	84,415	67,984	—	152,399
Production taxes	1,889	—	—	1,889
Gathering and transportation	9,795	13,133	—	22,928
Depreciation, depletion and amortization	73,268	112,277	8,493	194,038
Asset retirement obligations accretion	8,165	9,406	—	17,571
Ceiling test write-down of oil and natural gas properties	28,305	110,709	140,049	279,063
General and administrative expenses	24,817	34,923	—	59,740
Derivative loss	2,926	—	—	2,926
Total costs and expenses	233,580	348,432	148,542	730,554
Operating loss	(72,517)	(109,509)	(148,542)	(330,568)
Loss of affiliates	(109,853)	—	109,853	—
Interest expense:				
Incurred	92,607	184	—	92,791
Capitalized	(336)	(184)	—	(520)
Gain on exchange of debt	123,923	—	—	123,923
Other income, net	(6,520)	—	—	(6,520)
Loss before income tax expense (benefit)	(144,198)	(109,509)	(38,689)	(292,396)
Income tax expense (benefit)	(43,720)	344	—	(43,376)
Net loss	$ (100,478)	$ (109,853)	$ (38,689)	$ (249,020)

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2015
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Revenues	$ 290,212	$ 217,053	$ —	$ 507,265
Operating costs and expenses:				
Lease operating expenses	126,189	66,576	—	192,765
Production taxes	3,002	—	—	3,002
Gathering and transportation	9,209	7,948	—	17,157
Depreciation, depletion and amortization	201,154	172,214	—	373,368
Asset retirement obligations accretion	11,587	9,116	—	20,703
Ceiling test write-down of oil and natural gas properties	616,947	517,880	(147,589)	987,238
General and administrative expenses	39,009	34,101	—	73,110
Derivative gain	(14,375)	—	—	(14,375)
Total costs and expenses	992,722	807,835	(147,589)	1,652,968
Operating loss	(702,510)	(590,782)	147,589	(1,145,703)
Loss of affiliates	(464,931)	—	464,931	—
Interest expense:				
Incurred	101,542	3,050	—	104,592
Capitalized	(4,206)	(3,050)	—	(7,256)
Other expense, net	4,663	—	—	4,663
Loss before income tax benefit	(1,269,440)	(590,782)	612,520	(1,247,702)
Income tax benefit	(77,133)	(125,851)	—	(202,984)
Net loss	$ (1,192,307)	$ (464,931)	$ 612,520	$ (1,044,718)

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2017
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Operating activities:				
Net income	$ 82,530	$ 61,444	$ (64,292)	$ 79,682
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	81,378	71,456	2,848	155,682
Gain on exchange of debt	(7,811)	—	—	(7,811)
Amortization of debt items	1,715	—	—	1,715
Share-based compensation	7,191	—	—	7,191
Derivative gain	(4,199)	—	—	(4,199)
Cash receipts on derivative settlements, net	4,199	—	—	4,199
Deferred income taxes	217	—	—	217
Loss of affiliates	(61,444)	—	61,444	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(3,491)	1,121	—	(2,370)
Joint interest receivables	2,131	—	—	2,131
Insurance reimbursements	31,740	—	—	31,740
Income taxes	(17,586)	16,523	—	(1,063)
Prepaid expenses and other assets	3,447	(108,773)	108,564	3,238
Escrow deposit - Apache lawsuit	(49,500)	—	—	(49,500)
Asset retirement obligation settlements	(55,672)	(16,737)	—	(72,409)
Accounts payable, accrued liabilities and other	127,496	(7,967)	(108,564)	10,965
Net cash provided by operating activities	142,341	17,067	—	159,408
Investing activities:				
Investment in oil and natural gas properties and equipment	(105,179)	(24,869)	—	(130,048)
Changes in operating assets and liabilities associated with investing activities	16,072	7,802	—	23,874
Purchases of furniture, fixtures and other	(933)	—	—	(933)
Net cash used in investing activities	(90,040)	(17,067)	—	(107,107)
Financing activities:				
Payment of interest on 1.5 Lien Term Loan	(8,227)	—	—	(8,227)
Payment of interest on 2nd Lien PIK Toggle Notes	(7,335)	—	—	(7,335)
Payment of interest on 3rd Lien PIK Toggle Notes	(6,201)	—	—	(6,201)
Debt exchange costs	(421)	—	—	(421)
Other	(1,295)	—	—	(1,295)
Net cash used in financing activities	(23,479)	—	—	(23,479)
Increase in cash and cash equivalents	28,822	—	—	28,822
Cash and cash equivalents, beginning of period	70,236	—	—	70,236
Cash and cash equivalents, end of period	$ 99,058	$ —	$ —	$ 99,058

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2016
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Operating activities:				
Net loss	$ (100,478)	$ (109,853)	$ (38,689)	$ (249,020)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	81,433	121,683	8,493	211,609
Ceiling test write-down of oil and gas properties	28,305	110,709	140,049	279,063
Gain on exchange of debt	(123,923)	—	—	(123,923)
Debt issuance costs write-down/amortization of debt items	2,548	—	—	2,548
Share-based compensation	11,013	—	—	11,013
Derivative gain	2,926	—	—	2,926
Cash payments on derivative settlements	4,746	—	—	4,746
Deferred income taxes	28,048	344	—	28,392
Loss of affiliates	109,853	—	(109,853)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	1,630	(8,635)	—	(7,005)
Joint interest receivables	12	—	—	12
Income taxes	(64,274)	—	—	(64,274)
Prepaid expenses and other assets	(14,395)	(78,547)	77,996	(14,946)
Asset retirement obligations	(49,303)	(23,017)	—	(72,320)
Accounts payable, accrued liabilities and other	45,817	37,538	(77,996)	5,359
Net cash provided by (used in) operating activities	(36,042)	50,222	—	14,180
Investing activities:				
Investment in oil and natural gas properties and equipment	(37,418)	(11,188)	—	(48,606)
Changes in operating assets and liabilities associated with investing activities	4,340	(39,534)	—	(35,194)
Proceeds from sales of assets, net	1,000	500	—	1,500
Purchases of furniture, fixtures and other	(96)	—	—	(96)
Net cash used in investing activities	(32,174)	(50,222)	—	(82,396)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	340,000	—	—	340,000
Repayments of long-term debt – revolving bank credit facility	(340,000)	—	—	(340,000)
Issuance of 1.5 Lien Term Loan	75,000	—	—	75,000
Payment of interest on 1.5 Lien Term Loan	(2,570)	—	—	(2,570)
Debt exchange costs	(18,464)	—	—	(18,464)
Other	(928)	—	—	(928)
Net cash provided by financing activities	53,038	—	—	53,038
Decrease in cash and cash equivalents	(15,178)	—	—	(15,178)
Cash and cash equivalents, beginning of period	85,414	—	—	85,414
Cash and cash equivalents, end of period	$ 70,236	$ —	$ —	$ 70,236

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2015
(In thousands)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Operating activities:				
Net loss	$ (1,192,307)	$ (464,931)	$ 612,520	$ (1,044,718)
Adjustments to reconcile loss to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	212,741	181,330	—	394,071
Ceiling test write-down of oil and gas properties	616,947	517,880	(147,589)	987,238
Debt issuance costs write-down/amortization of debt items	4,411	—	—	4,411
Share-based compensation	10,242	—	—	10,242
Derivative loss	(14,375)	—	—	(14,375)
Cash payments on derivative settlements	6,703	—	—	6,703
Deferred income taxes	(77,421)	(125,851)	—	(203,272)
Earnings of affiliates	464,931	—	(464,931)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	39,078	(6,842)	—	32,236
Joint interest receivables	21,645	—	—	21,645
Income taxes	(7)	—	—	(7)
Prepaid expenses and other assets	(13,916)	122,977	(91,245)	17,816
Asset retirement obligations	(26,637)	(5,918)	—	(32,555)
Accounts payable, accrued liabilities and other	(141,608)	4,156	91,245	(46,207)
Net cash provided by (used in) operating activities	(89,573)	222,801	—	133,228
Investing activities:				
Investment in oil and natural gas properties and equipment	(31,534)	(198,627)	—	(230,161)
Changes in operating assets and liabilities associated with investing activities	(29,806)	(25,619)	—	(55,425)
Proceeds from sales of assets, net	372,939	—	—	372,939
Investment in subsidiary	(1,445)	—	1,445	—
Purchases of furniture, fixtures and other	(1,278)	—	—	(1,278)
Net cash provided by (used in) investing activities	308,876	(224,246)	1,445	86,075
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	263,000	—	—	263,000
Repayments of long-term debt – revolving bank credit facility	(710,000)	—	—	(710,000)
Issuance of 9.00% Second Lien Term Loan	297,000	—	—	297,000
Debt issuance costs	(6,669)	—	—	(6,669)
Other	(886)	—	—	(886)
Investment from parent	—	1,445	(1,445)	—
Net cash provided by (used in) financing activities	(157,555)	1,445	(1,445)	(157,555)
Increase in cash and cash equivalents	61,748	—	—	61,748
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	$ 85,414	$ —	$ —	$ 85,414

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,		
	2017	2016	2015
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 8,102.0	$ 7,932.5	$ 7,882.3
Unproved oil and natural gas properties and equipment	—	—	20.2
Accumulated depreciation, depletion and amortization (1) related to oil, NGLs and natural gas activities	(7,525.0)	(7,387.8)	(6,916.2)
Net capitalized costs related to producing activities	$ 577.0	$ 544.7	$ 986.3

(1) Includes ceiling test write-down in 2016 and 2015.

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,		
	2017	2016	2015
Costs incurred: (1)			
Proved properties acquisitions	$ 1.1	$ 1.3	$ 15.6
Exploration (2) (3)	62.0	4.8	152.4
Development	92.5	56.9	65.5
Unproved properties acquisitions	—	0.5	0.1
Total costs incurred in oil and gas property acquisition, exploration and development activities	$ 155.6	$ 63.5	$ 233.6

(1) Includes net additions from capitalized ARO of $21.3 million in 2017, net additions from capitalized ARO of $10.8 million in 2016, and net reductions from capitalized ARO of $0.4 million during 2015. These adjustments for ARO are associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.

(2) Includes seismic costs of $0.5 million, $0.2 million and $3.2 million incurred during 2017, 2016 and 2015, respectively.

(3) Includes geological and geophysical costs charged to expense of $4.2 million, $4.1 million and $5.7 million during 2017, 2016 and 2015, 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,		
	2017	2016	2015
Depreciation, depletion, amortization and accretion per Boe	$ 10.68	$ 13.77	$ 23.11

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 25% of our proved developed non-producing reserves as of December 31, 2017 so we may not be in a position to control the timing of all development activities. We are the operator for all of our proved undeveloped reserves as of December 31, 2017. In prior years, we were not the operator of 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, 2014	61.7	15.8	254.9	120.0	720.0
Revisions of previous estimates (2)	4.8	(0.9)	4.9	4.7	28.0
Revisions related to sold properties (3)	(12.1)	(4.8)	(2.9)	(17.4)	(104.3)
Extensions and discoveries (4)	2.4	0.2	8.8	4.1	24.4
Purchase of minerals in place (5)	—	—	6.1	1.0	6.1
Sales of reserves (6)	(13.5)	(2.1)	(20.2)	(19.0)	(113.8)
Production	(7.8)	(1.6)	(46.2)	(17.0)	(102.3)
Proved reserves as of Dec. 31, 2015	35.5	6.6	205.4	76.4	458.1
Revisions of previous estimates (7)	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 (8)	4.5	0.7	25.8	9.6	57.4
Extensions and discoveries (9)	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
Year-end proved developed reserves:					
2017	26.1	7.2	173.5	62.2	373.3
2016	26.6	7.6	183.1	64.7	388.2
2015	29.4	6.4	198.5	69.0	413.5
Year-end proved undeveloped reserves:					
2017 (10)	8.3	0.6	18.7	12.0	72.0
2016	6.3	0.6	14.7	9.3	55.8
2015	6.1	0.2	6.9	7.4	44.6

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) Includes upwards revisions of 7.4 MMBoe at the Ship Shoal 349 field (Mahogany), 1.9 MMBoe at our Brazo A-133 field, 1.3 MMBoe at out Atwater 575 field, 1.3 MMBoe at out Mississippi Canyon 243 field (Matterhorn), 1.1 MMBoe at our Fairway Field, partially offset by downward revisions due to price of 10.7 MMBoe. The revision for price excludes the Yellow Rose field sold during 2015.

(3) Revisions related to the Yellow Rose field during 2015, which were primarily due to price reductions, up to the date of the sale in October 2015.

(4) Primarily due to increases at our Ewing Bank 910 field.

(5) Primarily due to purchase of additional interest at our Brazos A-133 field.

(6) Related primarily to the sale of the Yellow Rose field in October 2015, which had estimated reserves at the date of sale of 19.0 MMBoe.

(7) Primarily related to upward revisions of 14.2 MMBoe, which included upward revisions of 3.8 MMBoe at our Viosca Knoll 823 (Tahoe/SE Tahoe) 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.

(8) 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 (Virgo) field. Additionally, increases of 3.4 MMBoe were due to price revisions.

(9) 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.

(10) We believe that we will be able to develop all but 1.8 MMBoe (approximately 15%) of the total of 12.0 MMBoe reserves classified as proved undeveloped (“PUDs”) at December 31, 2017, within five years from the date such reserves were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field (Matterhorn) where the field is being developed using a single floating tension leg platform requiring an extended sequential development plan. The platform cannot support a rig that would allow additional wells to be drilled, but can support a rig to allow sidetracking of wells. Two sidetrack PUD locations in this 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 2023.

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,			
	2017	2016	2015	2014
Oil - per barrel	$ 46.58	$ 36.28	$ 46.94	$ 91.12
NGLs per barrel	22.65	16.82	17.60	34.63
Natural gas per Mcf	2.86	2.47	2.50	4.27

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 2017 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,		
	2017	2016	2015
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 2,328.8	$ 1,818.4	$ 2,296.7
Future costs:			
Production	(813.8)	(691.5)	(840.1)
Development	(157.4)	(141.1)	(161.4)
Dismantlement and abandonment	(361.9)	(427.7)	(471.8)
Income taxes (1)	(74.8)	—	—
Future net cash inflows before 10% discount	920.9	558.1	823.4
10% annual discount factor	(180.3)	(79.8)	(209.5)
Total	$ 740.6	$ 478.3	$ 613.9

(1) No future income taxes were estimated for 2016 and 2015 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,		
	2017	2016	2015
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 478.3	$ 613.9	$ 1,702.8
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(315.3)	(218.6)	(289.1)
Net changes in price, net of future production costs	288.0	(275.2)	(1,455.6)
Extensions and discoveries, net of future production and development costs	119.3	—	65.3
Changes in estimated future development costs	(38.9)	(32.5)	(8.5)
Previously estimated development costs incurred	102.8	114.5	158.9
Revisions of quantity estimates	106.4	190.1	137.9
Accretion of discount	30.2	52.6	150.6
Net change in income taxes	(54.7)	—	600.8
Purchases of reserves in-place	—	—	6.0
Sales of reserves in-place	—	—	(401.4)
Changes in production rates due to timing and other	24.5	33.5	(53.8)
Net increase (decrease) in standardized measure	262.3	(135.6)	(1,088.9)
Standardized measure, end of year	$ 740.6	$ 478.3	$ 613.9

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, 2017 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, 2017, 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, 2017, 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, 2017 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
2.1	Purchase and Sale Agreement, dated as of August 31, 2015, by and among Ajax Resources, LLC, as Buyer, and W&T Offshore, Inc., as Seller (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed October 21, 2015 (File No. 001-32414))
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	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc., dated as of September 6, 2016 (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed September 6, 2016 (File No. 001-32414))
3.5	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 B to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2017 (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))

Exhibit Number	Description
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))
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))
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*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007 (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed February 26, 2007 (File No. 001-32414))
10.4*	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010 (File No. 001-32414))
10.5*	First Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013 (File No. 001-32414))
10.6*	Second Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013 (File No. 001-32414))

Exhibit Number	Description
10.7*	Third Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2016 (File No. 001-32414))
10.8*	Fourth Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2017 (File No. 001-32414))
10.9*	Form of Employment Agreement for Executive Officers other than the Chief Executive Officer (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 6, 2010 (File No. 001-32414))
10.10*	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))
10.11*	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))
10.12*	Form of Employment Agreement by and between W&T Offshore, Inc. and Thomas P. Murphy (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed August 6, 2010 (File No. 001-32414))
10.13*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Thomas P. Murphy, dated as of June 19, 2012 (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed June 22, 2012 (File No. 001-32414))
10.14	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))
10.15	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))
10.16	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))
10.17	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))

Exhibit Number	Description
10.18	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))
10.19	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))
10.20	$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))
10.21	Intercreditor Agreement, dated May 11, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as priority lien agent, Morgan Stanley Senior Funding, Inc., as second lien collateral trustee, and the various agents and lenders party thereto (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.22	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))
10.23	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))
10.24	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))
10.25	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))
10.26	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))
10.27	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))

Exhibit Number	Description
10.28*	Form of Executive Annual Incentive Agreement for Fiscal 2015 (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed November 6, 2015 (File No. 001-32414))
10.29*	Form of 2015 Executive Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.23 of the Company's Annual Report on Form 10-K, filed March 9, 2016 (File No. 001-32414))
10.30*	Form of Executive Annual Incentive Agreement for Fiscal 2016 (Incorporated by reference to Exhibit 10.9 of the Company's Quarterly Report on Form 10-Q, filed November 3, 2016 (File No. 001-32414))
10.31*	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))
10.32*	Form of Executive Annual Incentive Agreement for Fiscal 2017 (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed May 4, 2017 (File No. 001-32414))
10.33*	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))
12.1**	Ratio of Earnings to Fixed Charges
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.
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 March 2, 2018.

W&T OFFSHORE, INC.

By: /s/ John D. Gibbons
John D. Gibbons

Senior Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 2, 2018.

/s/ Tracy W. Krohn **Tracy W. Krohn**	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ John D. Gibbons **John D. Gibbons**	Senior 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 12.1

W&T Offshore, Inc.

Ratio of Earnings to Fixed Charges

The following table sets forth our ratios of consolidated earnings to fixed charges for the periods presented:

	Year Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
	(in thousands except ratios) (unaudited)				
Income (loss) before income taxes	$ 67,113	$ (292,396)	$ (1,247,702)	$ (16,120)	$ 80,096
Add: Fixed charges	46,091	93,063	104,870	87,193	85,902
Add: Amortization of capitalized interest	-	5,207	40,158	4,538	4,380
Less: Capitalized Interest	-	(520)	(7,256)	(8,526)	(10,058)
Earnings before fixed charges	$ 113,204	$ (194,646)	$ (1,109,930)	$ 67,085	$ 160,320
Fixed Charges:					
Interest expense, net of capitalized interest	$ 45,836	$ 92,271	$ 97,336	$ 78,396	$ 75,581
Capitalized interest	-	520	7,256	8,526	10,058
Portion of rental expense representative of an interest factor	255	272	278	271	263
Total fixed charges	$ 46,091	$ 93,063	$ 104,870	$ 87,193	$ 85,902
Ratio of earnings to fixed charges	2.5	N/A (1)	N/A (2)	N/A (3)	1.9

(1) The ratio was not meaningful. Earnings were inadequate to cover fixed charges for the year ended December 31, 2016 by $287.7 million, which included a ceiling test write-down of oil and gas properties of $279.1 million and a gain on exchange of debt of $123.9 million.

(2) The ratio was not meaningful. Earnings were inadequate to cover fixed charges for the year ended December 31, 2015 by $1,214.8 million, which included a ceiling test write-down of oil and gas properties of $987.2 million.

(3) The ratio was less than one-to-one coverage. Earnings were inadequate to cover fixed charges for the year ended December 31, 2014 by $20.1 million.

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. 333-214168) of W&T Offshore, Inc.,

(2) Registration Statement (Form S-3 No. 333-202946) 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, and

(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 March 2, 2018, 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, 2017.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 2, 2018

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent consultants, Netherland, Sewell & Associates, Inc. hereby consents to the incorporation by reference in the Annual Report on Form 10-K of W&T Offshore, Inc. to be filed on or about March 2, 2018, of information from our reserves report with respect to the reserves of W&T Offshore, Inc. dated January 24, 2018, and entitled “Estimate of Reserves and Future Revenue to the W&T Offshore, Inc. Interest in Certain Oil and Gas Properties Located Onshore Texas and in the Gulf of Mexico as of December 31, 2017,” and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2013, 2014, 2015 and 2016. We further consent to the incorporation by reference of information contained in our reports dated March 2, 2017 in the Registration Statements (Form S-3 Nos. 333-214168 and 333-202946) of W&T Offshore, Inc. and in the related Prospectuses and the Registration Statement (Form S-8 No. 333-219747) pertaining to the W&T Offshore, Inc. Long-Term Compensation Plan and the Registration Statement (Form S-8 No. 333-126252) pertaining to the W&T Offshore, Inc. Directors Compensation Plan. 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
March 2, 2018

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: March 2, 2018

/s/ TRACY W. KROHN

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

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Gibbons, 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: March 2, 2018

/s/ JOHN D. GIBBONS

John D. Gibbons
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Annual Report on Form 10-K for the year ended December 31, 2017 (the "Annual Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 2, 2018

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

Date: March 2, 2018

/s/ JOHN D. GIBBONS
John D. Gibbons
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

January 24, 2018

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, 2017, to the W&T Offshore, Inc. (W&T) interest in certain oil and gas properties located onshore Texas; 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.

We estimate the net reserves and future net revenue to the W&T interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue[1] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	22,382.0	6,588.2	153,092.1	943,225.5	716,946.8
Proved Developed Non-Producing	3,710.0	612.4	20,424.5	135,496.3	87,760.1
Proved Undeveloped	8,293.7	602.8	18,662.8	278,847.5	188,150.8
Total Proved	34,385.7	7,803.4	192,179.4	1,357,569.3	992,857.7

(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 one proved location that is scheduled to be drilled five years beyond the as-of date because of limitations with conductor slot availability. This location has been included based on the operators' declared intent to drill this well. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is W&T's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for W&T's share of state production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of $51.34 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 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 $46.58 per barrel of oil, $22.65 per barrel of NGL, and $2.863 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. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by W&T and are based on authorizations for expenditure (AFEs) prepared for internal approval and, if applicable, external interest owner approval. If an AFE was not available, W&T provided cost estimates based on recent activity similar in scope to the proposed project. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of W&T's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the W&T interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on W&T receiving its net revenue interest share of estimated future gross production after field usage and shrinkage. Additionally, although we are aware of transportation commitments that are in place for certain properties, the costs associated with any shortfalls or deficiencies would be immaterial to our analysis; no adjustments have been made to our estimates of future revenue to account for such commitments.

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
Petroleum Engineer

Date Signed: January 24, 2018

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

Date Signed: January 24, 2018

GSC:ARS

DEFINITIONS OF OIL AND GAS RESERVES

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

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4 -10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) th e 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 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which 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 which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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%

DEFINITIONS OF OIL AND GAS RESERVES

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

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

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

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

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

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

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

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

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

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resourc es 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.