W&T OFFSHORE INC
Form 10-K
March 02, 2018

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 (State or other jurisdiction of incorporation or organization)	72-1121985 (I.R.S. Employer Identification Number)
Nine Greenway Plaza, Suite 300	
Houston, Texas (Address of principal executive offices)	77046-0908 (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.

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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.

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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.

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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:

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- 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.

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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	Mcf – thousand cubic feet
MBbls – thousand barrels for crude oil, condensate or NGLs	MMcf – million cubic feet
Boe – barrel of oil equivalent	

MBoe – thousand barrels of oil equivalent	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	Mcf – thousand cubic feet
MBbls – thousand barrels for crude oil, condensate or NGLs	MMcf – million cubic feet
Boe – barrel of oil equivalent	Mcfe – thousand cubic feet of gas equivalent

MBoe – thousand barrels of oil equivalent	MMcfe – million cubic feet of gas equivalent

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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]			
				Oil	Natural Gas	% of	
	Oil	NGLs	Natural Gas	Equivalent	Equivalent	Total	PV-10 [3]
Classification of Proved Reserves [1]	(MMBbls)	(MMBbls)	(Bcf)	(MMBoe)	(Bcfe)	Proved	(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	Bcf – billion cubic feet
MMBoe – million barrels of oil equivalent	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

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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		Undeveloped		Total	
	Acreage Gross	Net	Acreage Gross	Net	Acreage 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	MMcf – million cubic feet
MBoe – thousand barrels of oil equivalent	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

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	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	Bcf – billion cubic feet
MMBoe – million barrels of oil equivalent	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):					