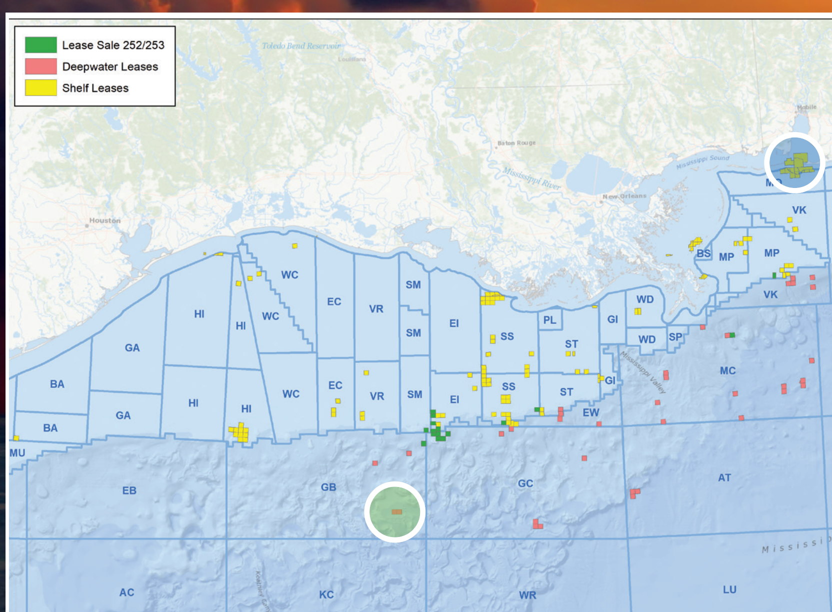
W&T OFFSHORE

Over 36 years of industry leadership in the Gulf of Mexico.

2019 ANNUAL REPORT

We enhanced our shallow water and deepwater portfolios with our 2019 Mobile Bay and Magnolia Acquisitions

We increased reserves by 81 million barrels of oil equivalent (MMBoe) and significantly grew production with our two Gulf of Mexico (GOM) acquisitions last year. We have a very good track record of reducing costs and enhancing value with all of our past acquisitions and we intend to do that with both Mobile Bay and Magnolia in 2020 and beyond. As shown on the map below, we also added nine new shallow water and eight new deepwater leases in GOM federal lease sales that together added 83,800 gross acres to our inventory.



WHO WE ARE

Founded in 1983, W&T Offshore, Inc. (W&T) is an independent oil and natural gas producer with operations in the GOM. For more than 36 years, we have grown through attractive property acquisitions, methodical integration and exploitation of those acquisitions, and successful development and exploratory drilling on our legacy fields. With working interests in 51 producing fields, in both federal and state waters, our leases cover approximately 815,000 gross acres, of which 595,000 acres are on the GOM shelf and 220,000 acres are in deepwater. Approximately 73% of our 2019 average daily production was in shallow water while the balance was in deepwater.

MOBILE BAY

- Acquired ExxonMobil's interests and operatorship in their shallow water producing properties in Mobile Bay as well as related onshore processing facilities in late August 2019
- Included 77 MMBoe of low decline, long-life, mostly proved developed producing natural gas reserves, 108,000 gross (95,600 net) acres and 3-D seismic data
- Allows for significant synergies, consolidations, and cost savings as we became the largest operator in the area
- Contains multiple future value enhancing opportunities including drilling leads and optimization of compression facilities
- Utilized our cash on hand and previously undrawn revolving credit facility to finance the acquisition and have since paid down a portion of that debt

MAGNOLIA

- Acquired ConocoPhillips' 75% interest in and operatorship of the deepwater Magnolia Field in Garden Banks blocks 783 and 784 in December 2019
- Added 4 MMBoe net proved reserves, of which 83% are proved developed producing and 72% are oil and 7% NGLs, and increased inventory by 11,500 gross (8,600 net) acres
- Provides upside from additional pay sands in existing well bores and potential opportunities for future drilling
- Utilized our available cash on hand to finance the acquisition
- Announced intent to acquire the remaining 25% working interest in the field in early March with an expected close on March 31, 2020

A LETTER FROM
TRACY W. KROHN

Fellow Shareholders

Over the past 36 years, W&T has been a leader in the Gulf of Mexico, and we continue to expand our strong asset base. We have grown through the right combination of attractive property acquisitions, methodical integration and exploitation of those acquisitions, and successful development and exploratory drilling on our legacy fields, all while maintaining our focus on generating strong free cash flow.

We completed two great acquisitions in 2019 for approximately $188 million that added meaningful production, significant reserves, and future drilling locations. We achieved a 100% success rate on the six wells drilled in 2019 and invested $125.7 million in capital expenditures, before acquisitions, that was below the low end of guidance. In addition, we added nine new shallow water and eight new deepwater leases in Gulf of Mexico federal lease sales.

We grew our production in the fourth quarter of 2019 to over 52,000 Boe per day, which was up more than 50% from a year ago. Financially, for the full year 2019, we reported net income of $74.1 million, as well as net cash from operations of $232.2 million, and we lowered per Boe operating and overhead costs.

Most important, we generated free cash flow well in excess of our capital expenditures, excluding acquisitions. So, in summary, we grew reserves, increased production, cut costs and generated free cash flow.

At the beginning of 2019, I told you that we were looking closely at acquisition opportunities and in the second half of 2019, we executed two very good transactions that met all of our stringent investment criteria.

We look for properties with existing good cash flow, upside that we can achieve with the drill bit, and the potential to increase near-term cash flow through workovers, recompletions and/or facility upgrades. We primarily use the cash we generate to fund drilling and make more acquisitions to consistently grow value. We also use our free cash flow to partially pay down our debt to protect our balance sheet.

On August 30, 2019, we closed our Gulf of Mexico Mobile Bay acquisition from ExxonMobil for $168 million, which included working interests in nine shallow water producing fields and related operatorship in the Mobile Bay area, making W&T the largest operator in the area. These are low decline assets and they are adjacent to our current operations thereby providing us the opportunity to recognize increased scale, rationalize operations and capture cost efficiencies to further grow cash flow. The acquisition also included their onshore gas processing facility that is near our Yellowhammer gas processing facility.

On December 12, 2019, we completed an oil-weighted producing property acquisition from ConocoPhillips for their 75% working interest and operatorship of the Magnolia Field in the central region of the deepwater Gulf of Mexico. The total gross purchase price was $20 million. The field provides upside from additional pay sands in existing well bores and potential opportunities for future drilling. Both acquisitions were funded from W&T's available cash on hand and our revolving credit facility.

The 2019 acquisitions added approximately 81 MMBoe of proved reserves as of year-end, which was higher than the 77MMBoe combined reserves as of the effective dates of each transaction. The increase to reserves was driven by synergies and operational cost savings already captured by W&T at Mobile Bay that were partially offset by lower year-over-year prices. The underlying technical analysis of the total field remained unchanged, but these lower costs allow for higher margins throughout the life of the asset thus extending the overall field life. In addition, there is the opportunity for further growth in reserves from potential field-life extensions with little or no capital as well as through drilling and facility upgrade opportunities. We have a very good track record of reducing costs and enhancing value with all of our past acquisitions and we intend to do that with both Mobile Bay and Magnolia in 2020 and beyond.

Additionally, in the first quarter of 2020, we signed a purchase and sale agreement to acquire the remaining 25% working interest in the Magnolia Field. We expect to close that transaction on March 31, 2020. This is another example of the attractive acquisition opportunities we are seeing across the Gulf of Mexico.

Well-timed and accretive acquisitions, coupled with strong operational results led to W&T's year-end 2019 SEC proved reserves increasing 87% to 157.4 MMBoe from 84.0 MMBoe at year-end 2018. The Company achieved an impressive proved reserve replacement rate of nearly 600% on 2019 production of 14.8 MMBoe. This included acquisitions, positive revisions, extensions and discoveries, and the impact of negative revisions due to pricing. At year end, about 40% of our reserves were liquids and approximately 85% of 2019 proved reserves were classified as proved developed. We also extended our reserve life ratio with 2019 acquisitions and successful drilling to 8.7 years.

The PV-10 value of W&T's SEC proved reserves at year-end 2019 was $1.3 billion, down about 9% from $1.4 billion at the end of 2018. This was driven by 11% lower oil pricing and a 16% reduction in natural gas pricing.

Our all-in reserve replacement cost in 2019, including acquisitions and drilling costs and considering all reserves and the impact of negative price revisions was $4.18 per Boe. We are particularly happy with our three-year 2017 through 2019 all-in reserve replacement cost of $5.05 per Boe, which we think is a very competitive cost for any E&P company.

Looking ahead to 2020, under current uncertain commodity pricing conditions, we intend to closely manage the factors that we can influence, including capital expenditures, operating costs, and G&A. This means that we will take a measured approach to drilling while continuing to fund our capital expenditures, excluding acquisitions, with available cash and cash generated from operations. We will also look to reduce our debt when our cash position is greater than our operating or capital needs.

At year-end 2019, we had $32.4 million in cash and $139.2 million of availability under our $250 million revolving bank credit facility. In early 2020, we paid down debt with a portion of our free cash flow and reduced the borrowings on our credit facility by $25 million to $80 million in borrowings. That was a 24% reduction in revolver debt.

While we have a substantial inventory of very attractive drilling opportunities, given the current macro pricing downturn, our capital spending plan in 2020 is now expected to be in the range of $15 to $25 million. While this is a large decline from our actual spending in 2019, the lower 2020 budget will have a minimal impact on our production expectations in 2020 due to the lower decline profile of our conventional producing properties. We also now expect to spend about $10 to $20 million on asset retirement obligations this year. This will give us maximum financial flexibility and facilitate generating free cash flow to reduce debt and potentially fund additional opportunities that we believe are available. We have significant flexibility to adjust our capital spending up or down at any time since we have no long-term rig contract commitments or drilling obligations. We will focus our drilling capital on low risk, high return projects and build on the 100% success rate that we achieved in both 2019 and 2018. Capex is not our only focus, as we are also forecasting a meaningful decrease in our total lease operating expenses per Boe compared to 2019.

Our management team's interests are highly aligned with those of our shareholders given our 34% stake in W&T's equity, which is among the very highest of any public E&P company. This alignment of interest ensures that we are truly incentivized to maximize shareholder value and mitigate risk. So, as you can see, we are tied to doing the right things for, and with, our shareholders in mind.

In closing, I want to thank our management team and all of our employees for their continued hard work and dedication, as well as our Board for their guidance and support. In our more than 36 years in the industry, we have experienced quite a number of commodity price cycles. We believe that we are well positioned today and remain confident in our ability to take advantage of attractive opportunities that a down cycle could present us.

Tracy W. Krohn
Founder, Chairman, Chief Executive Officer and President

March 18, 2020

Our Corporate Responsibility

At W&T, we fully acknowledge our responsibility to our employees and contractors and the communities where we operate, and the importance of the ongoing protection of the environment.

For many years, we have developed a good reputation based on our performance regarding the safety and health of our employees, serving as a community partner in our areas of operation, and protecting the environment in a sustainable manner that goes beyond compliance with federal and state regulations.

Our Commitment

We are committed to developing and producing oil and gas resources in a safe and environmentally responsible manner, while meeting or exceeding all regulatory requirements. Our management allocates resources and tools necessary to meet expectations and performance objectives and strives to create a working environment that encourages open communication about Health, Safety and Environmental (HSE) issues and concerns.

Our Safety and Environmental Management Systems (SEMS) program is designed to enable identifying, addressing, minimizing and managing of safety and environmental hazards and impacts that exist in or are created through any of our business activities. Our SEMS program satisfies the Bureau of Safety and Environmental Enforcement's SEMS requirements for offshore operators, and the Occupational Safety & Health Administration's Process Safety Management requirements for industrial facilities. The SEMS program establishes roles and responsibilities for all personnel working for W&T, as well as HSE goals and performance measures in order to achieve top tier safety and environmental performance. We track leading and lagging indicators for safety, environmental and compliance performance, and we address trends that develop through communication, training and personnel management.

HSE Training

We continuously invest in worker training to advance the SEMS program by increasing worker knowledge of safety and compliance trends, current or upcoming regulations and best industry practices from regulators and industry groups. Training is administered through a variety of methods including face-to-face presentations and discussions, computer-based training and third-party training.

Social

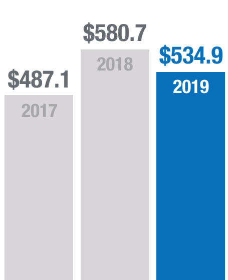
We actively support charitable organizations in the communities where we operate. We focus on helping children and families most in need, while aiding in the protection of the environment. We also support our employees who volunteer their time with these organizations.

Financial Highlights

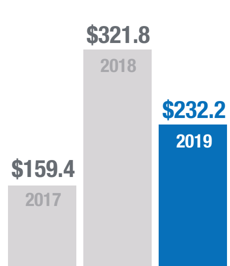
Year Ending December 31,

Income Statement (000s)		2019		2018		2017
Total Revenues	$	534,896	$	580,706	$	487,096
Operating Income	$	58,649	$	247,027	$	109,950
Net Income	$	74,086	$	248,827	$	79,682
Cash-Flow Statement (000s)						
Cash Provided by Operating Activities	$	232,227	$	321,763	$	159,408
Capex (oil and natural gas properties) excl acquisitions	$	125,706	$	106,191	$	106,174
Capex (acqusition of oil and natural gas properties)	$	188,019	$	16,782	$	—
Balance Sheet (000s)						
Total Assets	$	1,003,719	$	848,866	$	907,580
Long-Term Debt	$	719,533	$	633,535	$	992,052
Operating Data						
Net Sales:						
Oil (MMBbls)		6.7		6.7		7.1
NGLs (MMBbls)		1.3		1.3		1.4
Natural Gas (Bcf)		41.3		32.0		36.8
Total Oil Equivalent (MMBoe)		14.8		13.3		14.6
Average Daily Sales (MBoe/d)		40.6		36.5		39.9
Averaged Realized Sales Price:						
Oil ($/Bbl)	$	59.89	$	65.62	$	48.13
NGLs ($/Bbl)	$	17.60	$	28.40	$	23.35
Natural Gas ($/Mcf)	$	2.57	$	3.11	$	2.96
Oil Equivalent ($/Boe)	$	35.63	$	43.19	$	33.02
Proved Reserves						
Oil (MMBbls)		37.8		39.1		34.4
NGLs (MMBbls)		24.5		9.8		7.8
Natural Gas (Bcf)		571.1		210.5		192.2
Total Oil Equivalent (MMBoe)		157.4		84.0		74.2
Total Proved Developed (MMBoe)		133.8		67.0		62.2
Proved Undeveloped (MMBoe)		23.6		17.0		12.0
Proved Developed Reserves as a % of Proved Reserves		85%		80%		84%

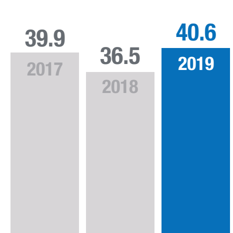
Revenue
($ in millions)



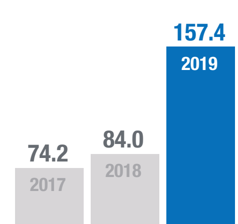
Cash Provided by Operating Activities
($ in millions)



Production
(MBoe/d)



Proved Reserves
(MMBoe)



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, 2019
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-32414

W&T OFFSHORE, INC.
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every interactive data file required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☑
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

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. ☐

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.00001	**WTI**	**New York Stock Exchange**

The aggregate market value of the registrant's common stock held by non-affiliates was approximately $463,023,000 based on the closing sale price of $4.96 per share as reported by the New York Stock Exchange on June 28, 2019.

The number of shares of the registrant's common stock outstanding on February 28, 2020 was 141,668,942.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Form 10-K.

W&T OFFSHORE, INC.
TABLE OF CONTENTS

This page intentionally left blank

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K ("Form 10-K") contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. Known material risks that may affect our financial condition and results of operations are discussed in Item 1A, Risk Factors, and market risks are discussed in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, of this Form 10-K and may be discussed or updated from time to time in subsequent reports filed with the Securities and Exchange Commission ("SEC"). Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We assume no obligation, nor do we intend, to update these forward-looking statements, unless required by law. Unless the context requires otherwise, references in this Form 10-K to "W&T," "we," "us," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries.

PART I

Item 1. *Business*

W&T Offshore, Inc. is an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties in the Gulf of Mexico. W&T Offshore, Inc. is a Texas corporation originally organized as a Nevada corporation in 1988, and successor by merger to W&T Oil Properties, Inc., a Louisiana corporation organized in 1983.

We have grown through acquisitions, exploration and development and currently hold working interests in 51 offshore producing fields in federal and state waters. We currently have under lease approximately 815,000 gross acres (550,000 net acres) spanning across the Outer Continental Shelf ("OCS") off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 595,000 gross acres on the conventional shelf and approximately 220,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 146 offshore structures, 104 of which are located in fields that we operate. We currently own interest in 240 productive wells, 177 of which we operate. Our interest in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. and our wholly-owned subsidiary, W & T Energy VI, LLC, a Delaware limited liability company and through our proportionately consolidated interest in Monza Energy, LLC ("Monza"), as described in more detail in *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K.

In managing our business, we are focused on optimizing production and increasing reserves in a profitable and prudent manner, while managing cash flows to meet our obligations and investment needs. Our cash flows are materially impacted by the prices of commodities we produce (crude oil and natural gas, and the natural gas liquids ("NGLs") extracted from the natural gas). In addition, the prices of goods and services used in our business can vary and impact our cash flows. During 2019, average realized commodity prices decreased from those we experienced during 2018 but were higher from those we experienced during 2017. Our margins in 2019 decreased from 2018 primarily due to lower average realized commodity prices. We measure margins using net income before net interest expense; income tax (benefit) expense; depreciation, depletion, amortization and accretion; unrealized commodity derivative gain or loss; amortization of derivative premiums; bad debt reserve; litigation; and other ("Adjusted EBITDA") as a percent of revenue, which is a not a financial measurement under generally accepted accounting principles ("GAAP"). We have historically increased our reserves and production through acquisitions, our drilling programs, and other projects that optimize production on existing wells. Our production increased 11.3% in 2019 from the prior year and we added 73.4 million barrels of oil equivalent ("MMBoe") of proved reserves in 2019, almost doubling our proved reserves and replacing our production by six times. (MMBoe was computed on an equivalency ratio as described below.) The 87% net increase in proved reserves year-over-year is primarily due to our acquisition of the Mobile Bay Properties (discussed below), as well as successful drilling, favorable technical revisions driven by improved well performance, recompletion, and workover efforts. Partially offsetting these increases were decreases in proved reserves from lower commodity prices and production. During 2019, we drilled and completed six additional wells which all began producing during 2019.

The Gulf of Mexico is an area where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid return on our invested capital. We have leveraged our experience in the conventional shelf (water depths of less than 500 feet) to develop higher impact capital projects in the Gulf of Mexico in both the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet and water depths of less than 500 feet). We have acquired rights to explore and develop new prospects and existing oil and natural gas properties in both the deepwater and the deep shelf, while at the same time continuing our focus on the conventional shelf. Our drilling efforts in recent years have included the deepwater of the Gulf of Mexico. The investment associated with drilling an offshore well and future development of an offshore project principally depends upon water depth, the depth of the well, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive on a per well basis than those on the conventional shelf. During each of the years 2019 and 2018, we participated in the drilling and completion of three deepwater wells.

In August 2019, we completed the purchase of Exxon Mobil Corporation's ("Exxon") interests in and operatorship of oil and gas producing properties in the eastern region of the Gulf of Mexico offshore Alabama and related onshore and offshore facilities and pipelines (the "Mobile Bay Properties"). After taking into account customary closing adjustments and an effective date of January 1, 2019, cash consideration was $169.8 million, of which substantially all was paid by us at closing. We also assumed the related asset retirement obligations ("ARO") and certain other obligations associated with these assets. The acquisition was funded from cash on hand and borrowings of $150.0 million under the Credit Agreement (defined below), which were previously undrawn. As of December 31, 2019, the Mobile Bay Properties had approximately 76.6 MMBoe of net proved reserves, of which 99% were proved developed producing reserves consisting primarily of natural gas and NGLs with 20% of the proved net reserves from liquids on an MMBoe basis, based on SEC pricing methodology. For the fourth quarter of 2019, the average production of the Mobile Bay Properties was approximately 18,500 net Boe per day. The properties include working interests in nine Gulf of Mexico offshore producing fields and an onshore treatment facility that are adjacent to existing properties owned and operated by us. With this purchase, we became the largest operator in the area.

During 2019, the percentage of our production from our fields on the conventional shelf increased to 73% in 2019 from 59% in 2018 of our total production (measured on an MMBoe basis) primarily due to acquisition of the Mobile Bay Properties and increases in production at the Ship Shoal 349 field ("Mahogany"). In the fourth quarter of 2019, which includes the Mobile Bay Properties' production for the entire quarter, the percentage of our production from our fields on the conventional shelf increased to 79% measured on an MMBoe basis. The Mobile Bay Properties accounted for 35% of our production measured on an MMBoe basis in the fourth quarter of 2019.

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

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent petroleum consultants, our total proved reserves at December 31, 2019 were 157.4 MMBoe compared to 84.0 MMBoe as of December 31, 2018. Approximately 78% of our proved reserves as of December 31, 2019 were classified as proved developed producing, 7% as proved developed non-producing and 15% as proved undeveloped. Classified by product, our proved reserves at December 31, 2019 were 24% crude oil, 16% NGLs and 60% natural gas. These percentages and other energy-equivalent measurements stated in this Form 10-K were determined using the industry standard energy-equivalent ratio of six thousand cubic feet (“Mcf”) of natural gas to one barrel (“Bbl”) of crude oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ significantly. Our total proved reserves had an estimated present value of future net revenues discounted at 10% (“PV-10”) of $1,302.5 million before consideration of cash outflows related to ARO. Our PV-10 after considering future cash outflows related to ARO was $1,117.6 million, and our standardized measure of discounted future cash flows was $986.9 million as of December 31, 2019. Neither PV-10 nor PV-10 after ARO is a financial measure defined under GAAP. For additional information about our proved reserves and a reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 in this Form 10-K.

To provide additional financial flexibility, we created a drilling joint venture program with private investors during 2018 (the “Joint Venture Drilling Program”) and completed nine drilling projects by the end of 2019. The Joint Venture Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in certain drilling projects. It also allows more projects to be taken on with our capital expenditures budget, thereby helping us reduce our level of concentration risk via diversification. In the Joint Venture Drilling Program, five wells came on line during 2019 and four wells came on line during 2018. For the first half of 2020, two wells are scheduled to be drilled and, assuming success, the wells are expected to start producing in late 2020 or early 2021. See *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K for additional information on the Joint Venture Drilling Program.

In October 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, we issued $625.0 million of 9.75% Senior Second Lien Notes due 2023 (the “Senior Second Lien Notes”), which were issued at par with an interest rate of 9.75% per annum that matures on November 1, 2023. Concurrently, we renewed our credit facility by entering into the Sixth Amended and Restated Credit Agreement (the “Credit Agreement”), dated as of October 18, 2018, among the Company, as borrower, the Guarantor Subsidiaries from time to time party thereto, Lenders from time to time party thereto and Toronto Dominion (Texas) LLC, as administrative agent (which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million). The borrowing base is subject to scheduled semi-annual redeterminations to occur around May 15th and November 14th each calendar year, and certain additional redeterminations that may be requested at the discretion of either the lenders or the Company. The borrowing base remained at $250.0 million as of December 31, 2019 following the latest redetermination. See *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for a full description of the transaction and the new debt instruments.

Our preliminary capital expenditure budget for 2020 has been established in the range of $50.0 million to $100.0 million, which includes our share of the Joint Venture Drilling Program, and excludes acquisitions. Our 2020 plans also include spending in the range of $15.0 million to $25.0 million for ARO. Based upon current commodity prices and production expectations for 2020, we believe that our cash flows from operating activities and cash on hand will be sufficient to fund our operations through year-end 2020 and provide cash balances to pay down a portion of the borrowings on the Credit Facility. While the amount and timing of our 2020 capital expenditures is largely discretionary and within our control, future cash flows are subject to a number of variables and additional capital expenditures may be required to more fully develop our properties. We are also currently evaluating additional acquisition opportunities, which, if successful, may increase our capital requirements in 2020 and beyond.

We continue to closely monitor current and forecasted commodity prices to assess what changes, if any, should be made to our 2020 plans. See *Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 in this Form 10-K for additional information.

Business Strategy

Our goal is to pursue high rate of return projects and develop oil and natural gas resources that allow us to grow our production, reserves and cash flow in a capital efficient manner, thus enhancing the value of our assets. We intend to execute the following elements of our business strategy in order to achieve this goal:

- Exploiting existing and acquired properties to add additional reserves and production;
- Exploring for reserves on our extensive acreage holdings and in other areas of the Gulf of Mexico;
- Acquiring reserves with substantial upside potential and additional leasehold acreage complementary to our existing acreage position at attractive prices; and
- Continuing to manage our balance sheet in a prudent manner and continuing our track record of financial flexibility in any commodity price environment. Over time, we expect to de-lever through free cash flow generated by our producing asset base, capital discipline, organic growth and acquisitions.

Our focus is on making profitable investments while operating within cash flow, maintaining sufficient liquidity, cost reductions and fulfilling our contractual, legal and financial obligations. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans.

Competition

The oil and natural gas industry is highly competitive. We currently operate in the Gulf of Mexico and compete for the acquisition of oil and natural gas properties and lease sales primarily on the basis of price for such properties. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas companies and individual producers and operators. Many of these competitors are large, well established companies that have financial and other resources substantially greater than ours and greater ability to provide the extensive regulatory financial assurances required for offshore properties. Our ability to acquire additional oil and natural gas properties, acquire additional leases and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties, finance investments and consummate transactions in a highly competitive environment.

Oil and Natural Gas Marketing and Delivery Commitments

We sell our crude oil, NGLs and natural gas to third-party customers. We are not dependent upon, or contractually limited to, any one customer or small group of customers. However, in 2019, approximately 40% of our revenues were to BP Products North America, 12% to Vitol Inc. and 11% to Shell Trading (US) Co., with no other customer comprising greater than 10% of our 2019 revenues. Due to the free trading nature of the oil and natural gas markets in the Gulf of Mexico, we do not believe the loss of a single customer or a few customers would materially affect our ability to sell our production. We do not have any agreements which obligate us to deliver material quantities to third parties.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulations as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE"), both agencies under the U.S. Department of the Interior ("DOI"), have adopted regulations pursuant to the Outer Continental Shelf Lands Act ("OCSLA") that apply to our operations on federal leases in the Gulf of Mexico.

The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. Sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at uncontrolled market prices. The FERC also regulates rates and service conditions for the interstate transportation of liquids, including crude oil, condensate and NGLs, under various statutes.

The Federal Trade Commission ("FTC"), the FERC and the Commodity Futures Trading Commission ("CFTC") hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. We are required to observe the market related regulations enforced by these agencies with regard to our physical sales of crude oil or other energy commodities, and any related hedging activities that we undertake. Any violation of the FTC, FERC, and CFTC prohibitions on market manipulation can result in substantial civil penalties amounting to over $1.0 million per violation per day.

These departments and agencies have substantial enforcement authority and the ability to grant and suspend operations, and to levy substantial penalties for non-compliance. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

Federal leases. Most of our offshore operations are conducted on federal oil and natural gas leases in the OCS waters of the Gulf of Mexico. These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms. These leases require compliance with the BOEM, the BSEE, and other government agency regulations and orders that are subject to interpretation and change. The BSEE also regulates the plugging and abandonment of wells located on the OCS and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines on the OCS (collectively, these activities are referred to as "decommissioning"), while the BOEM governs financial assurance requirements associated with those decommissioning obligations.

Decommissioning and financial assurance requirements. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In 2016, the BOEM under the Obama Administration issued Notice to Lessees and Operators ("NTL") #2016-N01 ("NTL #2016-N01") to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, rights of way ("ROWs") and rights of use and easement ("RUEs"). NTL #2016-N01 became effective in September 2016, but in the Spring of 2017, the BOEM under the Trump Administration has since extended indefinitely the start date for implementation. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities. See *Risk Factors* under Part I, Item 1A, *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 and *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K for more discussion on decommissioning and financial assurance requirements.

Reporting of decommissioning expenditures. During late 2015, the BSEE issued a final rule requiring lessees to submit summaries of actual expenditures for decommissioning of wells, platforms, and other facilities required under the BSEE's existing regulations. The BSEE has reported that it will use this summary information to better estimate future decommissioning costs, and the BOEM typically relies upon the BSEE's estimates to set the amount of required bonds or other forms of financial security in order to minimize the government's perceived risk of potential decommissioning liability.

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

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in 1992, the interstate natural gas transportation and marketing system allows non-pipeline natural gas sellers, including producers, to effectively compete with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the effect of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. The rates for such storage and transportation services are subject to FERC ratemaking authority, and FERC exercises its authority either by applying cost-of-service principles or granting market based rates. Similarly, the natural gas pipeline industry is subject to state regulations, which may change from time to time.

The OCSLA, which is administered by the BOEM and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the OCS market, to provide producers and shippers assurance of open access service on pipelines located on the OCS, and to provide non-discriminatory rates and conditions of service on such pipelines. The BOEM issued a final rule, effective August 2008, which implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS.

In 2007, the FERC issued rules ("Order 704") requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million British thermal units ("MMBtu") during a calendar year must annually report such sales and purchases to the FERC to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state legislatures, state commissions and the courts. The natural gas industry historically has been very heavily regulated. As a result, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and the states will continue.

While these federal and state regulations for the most part affect us only indirectly, they are intended to enhance competition in natural gas markets. We cannot predict what further action the FERC, the BOEM or state regulators will take on these matters. However, we do not believe that any such action taken will affect us differently, in any material way, than other natural gas producers with which we compete.

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

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

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

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and the BSEE continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEM and the BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures.

Environmental Regulations

General. We are subject to complex and stringent federal, state and local environmental laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and producing operations, the amounts and types of materials that may be released into the environment, the discharge and disposal of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often costly to comply with, and a failure to comply may result in substantial administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures, the occurrence of restrictions, delays or cancellations in the permitting, or development or expansion of projects and the issuance of orders enjoining some or all of our operations in affected areas. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict joint and several liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent and address pollution, such as the closure of inactive oil and gas waste pits and the plugging of abandoned wells. The regulatory burden on the oil and gas industry increases our cost of doing business and consequently affects our profitability. The cost of remediation, reclamation and decommissioning, including abandonment of wells, platforms and other facilities in the Gulf of Mexico is significant. These costs are considered a normal, recurring cost of our on-going operations. Our competitors are subject to the same laws and regulations.

Hazardous Substances and Wastes. The federal Comprehensive Environmental Response, Compensation, and Liability Act, as amended, ("CERCLA") imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons are subject to strict joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies.

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"), regulates the generation, transportation, storage, treatment and disposal of non-hazardous and hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and certain other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste", and the disposal of such oil and natural gas exploration, development and production wastes is regulated under less onerous non-hazardous waste requirements, usually under state law. There have been unsuccessful attempts made from time to time to remove this exclusion. The removal of this exclusion could have a material adverse effect on our results of operations and financial position, and it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future.

Standards have been developed under RCRA and/or state laws for worker protection from exposure to Naturally Occurring Radioactive Materials (“NORM”); treatment, storage, and disposal of NORM and NORM waste; management of NORM-contaminated waste piles, containers and tanks; and limitations on the relinquishment of NORM contaminated land for unrestricted use. Historically, we have not incurred any material expenditures in connection with our compliance with the existing RCRA and applicable state laws related to NORM waste.

Air Emissions and Climate Change. Air emissions from our operations are subject to the federal Clean Air Act, as amended (“CAA”), and comparable state and local requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For example, in 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard for ground level ozone from 75 to 70 parts per billion. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either “attainment/unclassifiable,” “unclassifiable” or “non-attainment.”

In the absence of federal legislation limiting greenhouse gases (“GHG”) emissions, the EPA has determined that GHG emissions present a danger to public health and the environment, and it has adopted regulations that, among other things, restrict emissions of GHG under existing provisions of the CAA and may require the installation of control technologies to limit emissions of GHG. For example, in June 2016, the EPA published a final rule establishing new source performance standards that require new, modified, or reconstructed facilities in the oil and natural gas sector to reduce methane gas and volatile organic compound emissions. The 2016 rule would apply to any new or significantly modified facilities that we construct in the future that would otherwise emit large volumes of GHG together with other criteria pollutants. The 2016 new source performance standards regulate GHGs through limitations on emissions of methane. However, on September 24, 2019, the EPA published a proposal to amend the 2016 regulations in a manner that, among other things, would remove sources in the transmission and storage segment from the oil and natural gas source category and rescind the methane-specific requirements applicable to sources in the production and processing segments of the industry. As an alternative, the EPA is also proposing to rescind the methane-specific requirements that apply to all sources in the oil and natural gas industry, without removing the transmission and storage sources from the current source category. Under either alternative, the EPA plans to retain emissions limits for volatile organic compounds. Public comments on the proposed rulemaking were due to be submitted by November 25, 2019. Whether these proposed standards will be implemented, on what date and exactly what they will require is unknown 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 oil and natural resource release related damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. In January 2018, the BOEM raised OPA’s damages liability cap to $137.7 million; however, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party failed to report a spill or cooperate fully in the cleanup. OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill, and to prepare and submit for approval oil spill response plans. These oil spill response plans must detail the action to be taken in the event of a spill; identify contracted spill response equipment, materials, and trained personnel; and identify the time necessary to deploy these resources in the event of a spill. In addition, OPA currently requires a minimum financial responsibility demonstration of between $35.0 million and $150.0 million for companies operating on the OCS. We are currently required to demonstrate, on an annual basis, that we have ready access to $150.0 million that can be used to respond to an oil spill from our facilities on the OCS.

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the monitoring and discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The EPA has also adopted regulations requiring certain onshore oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. The treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from our onshore gas processing plant may have significant costs. Obtaining permits has the potential to delay, restrict or cancel the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil.

Marine Protected Areas and Endangered and Threatened Species. Executive Order 13158, issued in May 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. In addition, Federal Lease Stipulations include regulations regarding the taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species).

Certain flora and fauna that have been officially classified as "threatened" or "endangered" are protected by the federal Endangered Species Act, as amended ("ESA"). This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. Additionally, the U.S. Fish and Wildlife Service may make determinations on the listing of species as threatened or endangered under the ESA and litigation with respect to the listing or non-listing of certain species may result in more fulsome protections for non-protected or lesser-protected species. We conduct operations on leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. During 2017, we reached an agreement with the various governmental agencies to remove the topside structure on our non-producing platform located in a National Marine Sanctuary in the U.S. Gulf of Mexico and leave the bottom of the platform structure below the water line in place. The project was completed during 2018 and allows the marine growth attached to and around the structure to remain and continue to grow. Unique regulations related to operations in a sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels.

Other federal statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Emergency Planning and Community Right-to-Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Magnuson-Stevens Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and related implementing regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands. These and other protected areas may require certain mitigation measures to avoid harm to wildlife, and such laws and regulations may impose substantial liabilities for pollution resulting from our operations. The 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, 2019, we employed 291 people. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, other reports and amendments to those reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at *www.wtoffshore.com.* These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Form 10-K and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., Nine Greenway Plaza, Suite 300, Houston, Texas 77046 or by calling (713) 297-8024. Information on our website is not a part of this Form 10-K.

Item 1A. Risk Factors

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to us and our industry could materially impact our future performance and results of operations. We have provided below a list of known material risk factors that should be reviewed when considering buying or selling our securities. These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

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

Crude oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond our control. Depressed oil, natural gas or NGL prices could adversely affect our business, financial condition, cash flow, liquidity or results of operations and could affect our ability to fund future capital expenditures needed to find and replace reserves, meet our financial commitments and to implement our business strategy.

The price we receive for our crude oil, NGLs and natural gas production directly affects our revenues, profitability, access to capital, ability to produce these commodities economically and future rate of growth. Historically, oil, NGLs and natural gas prices have been volatile and subject to wide price fluctuations in response to domestic and global changes in supply and demand, economic and legal forces, events and uncertainties, and numerous other factors beyond our control, including:

- changes in global supply and demand for crude oil, NGLs and natural gas;
- events that impact global market demand (e.g. the reduced demand following the recent coronavirus outbreaks);
- the actions of the Organization of Petroleum Exporting Countries ("OPEC") and certain other countries;
- the price and quantity of imports of foreign crude oil, NGLs, natural gas and liquefied natural gas;
- acts of war, terrorism or political instability in oil producing countries;
- national and global economic conditions;
- domestic and foreign governmental regulations and taxes;
- political conditions and events, including embargoes, affecting oil-producing activities;
- the level of domestic and global oil and natural gas exploration and production activities;
- the level of global crude oil, NGLs and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- the price, availability and acceptance of alternative fuels;
- cyberattacks on our information infrastructure or systems controlling offshore equipment;
- activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize or eliminate future emissions of carbon dioxide, methane gas and other GHG;
- the availability of pipeline and third party processing capacity; and
- geographic differences in pricing.

These factors and the volatility of the energy markets, which we expect to continue, make it extremely difficult to predict future commodity prices with any certainty. The average price for oil decreased during 2019 compared to 2018, but was higher compared to the average prices in 2017 and 2016, while prices for natural gas and NGLs decreased to their lowest levels since 2016.

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

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

Availability of borrowings and letters of credit under our Credit Agreement is determined by establishment of a borrowing base, which is periodically redetermined during the year based on our lenders' review of crude oil, NGLs and natural gas prices and on our proved reserves. During 2019, there were no changes to our borrowing base under the Credit Agreement, but during 2018, the borrowing base was increased from $150.0 million to $250.0 million. The borrowing base is subject to scheduled semi-annual redeterminations to occur around May 15th and November 14th of each year and additional redeterminations that may be requested at the discretion of either the lenders or the Company. The borrowing base could be reduced in the future as a result of lower commodity prices, our lenders' outlook for future prices or our inability to replace reserves as a result of constrained capital spending. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base; such excess (referred to as a "Borrowing Base Deficiency") is required to be repaid within 150 days in five 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 baskets, financial covenants or ratios.

We may not have the financial resources in the future to repay a Borrowing Base 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 a Borrowing Base Deficiency that may result from a borrowing base redetermination under our Credit Agreement may result in a cross-default under our other debt agreement. If crude oil, NGLs and natural gas prices fall back to the levels experienced in 2016, this would adversely affect our cash flow, which could result in reductions in our borrowing base, adversely affect prospects for alternative credit availability or affect our ability to satisfy our covenants and ratios under our Credit Agreement.

We have a significant amount of indebtedness and limited borrowing capacity under our Credit Agreement. Our leverage and debt service obligations may have a material adverse effect on our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.

As of December 31, 2019, we had $730.0 million principal amount of indebtedness outstanding, all of which was secured, and additionally had $5.8 million of letters of credit obligations outstanding. Our borrowing availability under our Credit Agreement was $139.2 million as of December 31, 2019, as we had $105.0 million in borrowings in addition to the letters of credit obligations outstanding. Our leverage and debt service obligations could:

- increase our vulnerability to general adverse economic and industry conditions (e.g. the reduced demand following the recent coronavirus outbreaks);
- limit our ability to fund future working capital requirements, capital expenditures and ARO, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets;
- limit our opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt obligations or to comply with any restrictive terms of our debt obligations;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impair our ability to obtain additional financing in the future; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. Substantially all of our oil, NGLs and natural gas properties are pledged as collateral under our Credit Agreement and are also pledged as collateral on a subordinate basis under the Indenture of the Senior Second Lien Notes (the "Indenture") dated as of October 18, 2018, entered into by and among the Company, the Guarantors, and Wilmington Trust, National Association, as trustee (the "Trustee"). Lower crude oil, NGLs and natural gas prices in the future would adversely affect our cash flow and could result in reductions in our borrowing base, reduce prospects for alternate credit availability, and affect our ability to satisfy the covenants and ratios under our Credit Agreement. Asset sales may also reduce available collateral and availability under our Credit Agreement. In addition, we cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations.

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

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

We and our subsidiaries may incur substantial additional indebtedness in the future, subject to the terms of our debt agreements. As of December 31, 2019, we had $730.0 million principal amount of secured indebtedness. The components of our indebtedness are:

- $105.0 million outstanding under our Credit Agreement; and
- $625.0 million in aggregate principal amount of 9.75% Senior Second Lien Notes.

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

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

The indentures and credit agreements governing our indebtedness contain a number of significant restrictive covenants in addition to covenants restricting the incurrence of additional debt. These covenants limit our ability and the ability of our restricted subsidiaries, among other things, to:

- make loans and investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of our company;
- engage in transactions with our affiliates;
- pay dividends or make other distributions on capital stock or indebtedness; and
- create unrestricted subsidiaries.

Our Credit Agreement requires us, among other things, to maintain certain financial ratios and satisfy certain financial condition tests or reduce our debt. These restrictions may also limit our ability to obtain future financings, withstand a future downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us from the restrictive covenants under our indentures governing our outstanding notes.

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

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

Lower crude oil, NGLs and natural gas prices will adversely affect our cash flow and may lead to further reductions in the borrowing base, which could also lead to reduced prospects for alternate credit availability. The capital markets we have historically accessed as an alternative source of equity and debt capital may be constrained. Other capital sources may arise with significantly different terms and conditions. Certain investors may exclude oil and gas companies from their investing portfolios due to environmental, social and governance factors. 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, 2019, we had $730.0 million principal amount of secured indebtedness outstanding. If in the future we default on any of our secured debt, we cannot provide assurance that the proceeds from the sale of the collateral will be sufficient to repay all of our secured debt in full. In addition, we have certain rights to issue or incur additional secured debt, including up to $139.2 million as of December 31, 2019, available for borrowing under our Credit Agreement, that would be secured by additional liens on the collateral and an issuance or incurrence of such additional secured debt would dilute the value of the collateral securing our outstanding secured debt. If the proceeds of any sale of the collateral are not sufficient to repay all amounts due in respect of our secured debt, then claims against our remaining assets to repay any amounts still outstanding under our secured obligations would be unsecured and our ability to pay our other unsecured obligations and any distributions in respect of our capital stock would be significantly impaired.

The collateral securing the various issues of our secured debt has not been appraised. The value of the collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers for the collateral. The value of the assets pledged as collateral for our secured debt could be impaired in the future as a result of changing economic conditions, commodity prices, competition or other future trends. Likewise, we cannot provide assurance that the pledged assets will be saleable or, if saleable, that there will not be substantial delays in their liquidation. In addition, to the extent that third parties hold prior liens, such third parties may have rights and remedies with respect to the property subject to such liens that, if exercised, could adversely affect the value of the collateral securing our secured debt.

With respect to some of the collateral securing our secured debt, any collateral trustee's security interest and ability to foreclose on the collateral will also be limited by the need to meet certain requirements, such as obtaining third party consents, paying court fees that may be based on the principal amount of the parity lien obligations and making additional filings. If we are unable to obtain these consents, pay such fees or make these filings, the security interests may be invalid and the applicable holders and lenders will not be entitled to the collateral or any recovery with respect thereto. We cannot provide assurance that any such required consents, fee payments or filings can be obtained on a timely basis or at all. These requirements may limit the number of potential bidders for certain collateral in any foreclosure and may delay any sale, either of which events may have an adverse effect on the sale price of the collateral. Therefore, the practical aspect of realizing value from the collateral may, without the appropriate consents, fees and filings, be limited.

We may be unable to provide the financial assurances in the amounts and under the time periods required by the BOEM if the BOEM submits future demands to cover our decommissioning obligations. If in the future the BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. As of the filing date of this Form 10-K, we are in compliance with our financial assurance obligations to the BOEM and have no outstanding BOEM orders, requests or financial assurance obligations. The BOEM, however, could in the future make demands for additional financial assurances covering our obligations under our properties, which could exceed the Company's capabilities to provide. If the BOEM issues future orders to provide additional surety bonds or other additional financial assurances to cover these obligations and we fail to comply with such future orders, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, suspending operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

We may be required to post cash collateral pursuant to our agreements with sureties under our existing or future bonding arrangements, which could have a material adverse effect on our liquidity and our ability to execute our capital expenditure plan, our ARO plan and comply with our existing debt instruments.

Pursuant to the terms of our agreements with various sureties under our existing bonding arrangements, including the arrangements entered into in connection with our acquisition of the Mobile Bay Properties, or under any future bonding arrangements we may enter into, we may be required to post collateral at any time, on demand, at the surety's sole discretion. If additional collateral is required to support surety bond obligations, this collateral would probably be in the form of cash or letters of credit. We cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for future bonds.

If we are required to provide additional collateral, our liquidity position will be negatively impacted and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing, we may be forced to reduce our capital expenditures in the current year or future years, may be unable to execute our ARO plan or may be unable to comply with our existing debt instruments. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 in this Form 10-K for additional information.

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

Accounting rules applicable to us require that we review the carrying value of our oil and natural gas properties quarterly for possible impairment. Impairment of proved properties under our full cost oil and gas accounting method is largely driven by the present value of future net revenues of proved reserves estimated using the SEC mandated 12-month unweighted first-day-of-the-month commodity prices. In addition to commodity prices, impairment assessments of proved properties include the evaluation of development plans, production data, economics and other factors. Such write-downs associated with impairments would constitute a non-cash charge to earnings. We experienced impairment write-downs of our oil and gas properties in 2016 and 2015 primarily as a result of oil and natural gas price declines, but did not incur any write-downs during 2019, 2018 or 2017. If prices fall significantly below current levels, this may cause write-downs during 2020 or in future periods. In addition, lower crude oil, NGLs and natural gas prices may reduce our estimates of the proved reserve volumes that may be economically recovered, which would reduce the total value of our proved reserves.

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

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

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

Our PUDs comprised 15% of our total proved reserves as of December 31, 2019 and require additional expenditures and/or activities to convert these into producing reserves. As circumstances change, we cannot provide assurance that all future expenditures will be made and that activities will be entirely successful in converting these reserves into proved producing reserves or PUDs during the time periods we have planned, at the costs we have budgeted, which could result in the write-off of previously recognized proved reserves. We are the operator for substantially all of our PUDs as of December 31, 2019. In the future, however, we could have more of our PUDs in non-operated fields, which may put us in a position of not being able to control the timing of development activities for the non-operated fields.

Relatively short production periods for our Gulf of Mexico properties based on proved reserves subject us to high reserve replacement needs and require significant capital expenditures to replace our proved reserves at a faster rate than companies whose proved reserves have longer production periods. Our failure to replace those proved reserves would result in decreasing proved 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. Proved reserves in the Gulf of Mexico generally have shorter reserve lives than proved reserves in many other producing regions of the United States due to the difference in rules related to booking proved undeveloped reserves between conventional and unconventional basins. Our independent petroleum consultant estimates that 35% of our total proved reserves will be depleted within three years. As a result, our need to replace proved reserves and production from new investments is relatively greater than that of producers who recover lower percentages of their proved reserves over a similar time period, such as those producers who have a larger portion of their proved reserves in areas other than the Gulf of Mexico. We may not be able to develop, find or acquire additional proved reserves in sufficient quantities to sustain our current production levels or to grow production beyond current levels. 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 obtain new oil and gas leases or replace reserves, we will not be able to sustain production at current levels, which may have a material adverse effect on our business, financial condition, or results of operations.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful exploration, development or acquisition activities, our proved reserves and production will decline over time. Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures and acquisitions with cash on hand, cash provided by operating activities, securities offerings and bank borrowings. The capital markets we have historically accessed may be constrained because of our leverage and we believe our access to capital markets may be limited in the future. Excluding acquisitions, our capital expenditures in 2019 were higher than the amount spent in 2018. The higher end of our capital expenditure budget range for 2020 is substantially the same as the amount spent in 2019, excluding acquisitions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, the prices of oil, NGLs and natural gas, and our success in developing and producing new reserves. Any reductions in our capital expenditures to stay within internally generated cash flow (which could be adversely affected if commodity prices decline) and cash on hand will make replacing depleted reserves more difficult. These limitations in the capital markets and our current capital budget may adversely affect our production levels. We cannot be certain that financing for future capital expenditures will be available if needed, and to the extent required, on acceptable terms. For additional financing risks, see "*–Risks Relating to Our Industry, Our Business and Our Financial Condition*."

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

In recent years, our drilling efforts have included deepwater projects in the Gulf of Mexico. The BSEE and the BOEM have over time imposed new and more stringent permitting procedures, safety regulations and environmental regulations for wells in the deepwater of federal waters. Compliance with these regulatory requirements, and together with uncertainties or inconsistencies in decisions and rulings by governmental agencies, have impacted the manner in which we have conducted our business in the past. Examples of areas where these stringent regulations have affected operations include new or amended measures for obtaining approval of drilling permits, exploration plans, development plans, oil spill-response submissions and decommissioning plans. These stringent regulations, and possible additional regulatory initiatives, could result in increased cost to our development efforts and ongoing business operations.

Moreover, the trend in the United States over the past decade has been for these governmental agencies to continue to evaluate and, as necessary, develop and implement new, more restrictive requirements, although in recent years under the Trump Administration, there have been actions seeking to mitigate certain of those more rigorous standards. For example, in 2016, the BSEE under the Obama Administration published a final rule on well control that, among other things, imposed 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. Pursuant to certain executive orders issued by President Trump in 2017, however, the BSEE initiated a review of the well control rule and other offshore rules and initiatives to determine whether they are consistent with the stated policy of encouraging energy exploration and production, while ensuring that any such activity is safe and environmentally responsible. One consequence of this review is that in May 2019, the BSEE published final revisions to the existing 2016 rule on well control that, among other things, eliminated the requirement for a BSEE-approved verification organization to oversee third parties which provide certifications of certain critical well control functions. Another consequence of this BSEE review was an indefinite delay in implementation of NTL #2016-N01 that, if implemented, could result in significant increases in financial assurances for our operating on the OCS. There exists the possibility that certain of these recent mitigatory actions under the Trump Administration could be withdrawn or revised in the future as a result of litigation or by a different presidential administration to impose or re-implement more stringent standards. Moreover, due primarily to the threat of climate change arising from GHG emissions, certain candidates seeking the office of President of the United States in 2020 have pledged to take actions to ban new mineral leases on federal properties, including offshore leases on the OCS. Additionally, litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

These regulatory actions, or any new rules, regulations, or legal initiatives or controls, whether under the Trump Administration or another administration, that impose increased costs or more stringent operational standards could delay or disrupt our operations, result in increased supplemental bonding and costs and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases. Also, if material spill incidents were to occur in the future, the United States could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We are and could be exposed to uninsured losses in the future. We currently carry multiple layers of insurance coverage in our Energy Package (defined as certain insurance policies relating to our oil and gas properties which include named windstorm coverage) covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. With respect to coverage for named windstorms, we have a $162.5 million aggregate limit covering all of our higher valued properties, and a $150.0 million aggregate limit for all of our other properties, subject to a retention of $30.0 million. Included within the $162.5 million aggregate limit is total loss only (“TLO”) coverage on our Mahogany platform, which has no retention.

The occurrence of a significant accident or other event not covered in whole or in part by our insurance could have a material adverse impact on our financial condition and operations. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. In May and June 2019, we entered into our insurance policies covering well control and hurricane damage (described above) and for general liability and pollution. These policies are effective for one year from their respective execution date. These policies reduce, but in no way totally mitigate our risk as we are exposed to amounts for retention and co-insurance, limits on coverage and events that are not insured. Renewal of these policies at a cost commensurate with current premiums is not assured. We also have other smaller per-occurrence retention amounts for various other events. In addition, pollution and environmental risks are generally not fully insurable, as gradual seepage and pollution are not covered under our policies. Because third-party drilling contractors are used to drill our wells, we may not realize the full benefit of workmen’s compensation laws in dealing with their employees.

OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. We are currently required to demonstrate, on an annual basis, that we have ready access to $150.0 million that can be used to respond to an oil spill from our facilities on the OCS. If OPA is amended to increase the minimum level of financial responsibility, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended, or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

For some risks, we have not obtained insurance as we believe the cost of available insurance is excessive relative to the risks presented. We may take on further risks in the future if we believe the cost is excessive to the risks. The occurrence of a significant event not fully insured or indemnified against losses could have a material adverse effect on our financial condition and results of operations. See *Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Hurricane Remediation, Insurance Claims and Insurance Coverage* under Part II, Item 7 in this Form 10-K for additional information on insurance coverage.

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, and as required under our Credit Agreement, we periodically enter into oil and natural gas price commodity derivative positions with respect to a portion of our expected production. During the fourth quarter of 2019, we entered into derivative contracts for natural gas, which expire in December 2022 and crude oil derivative contracts, which expire in December 2020. During the fourth quarter of 2018, we entered into commodity derivative contracts for crude oil, which will expire in May 2020. We may enter into more derivative 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 10 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information on derivative transactions.

Competition for oil and natural gas properties and prospects is intense; some of our competitors have larger financial, technical and personnel resources that may give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil, NGLs and natural gas and securing trained personnel. Many of our competitors have financial resources that allow them to obtain substantially greater technical expertise and personnel than we have. We actively compete with other companies in our industry when acquiring new leases or oil and natural gas properties. For example, new leases acquired from the BOEM are acquired through a “sealed bid” process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay or finance. On the acquisition opportunities made available to us, we compete with other companies in our industry for such properties through a private bidding process, direct negotiations or some combination thereof. Our competitors may have significantly more capital resources and less expensive sources of capital. In addition, they may be able to generate acceptable rates of return from marginal prospects due to their lower costs of capital. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence. Additional requirements imposed on us and our ability to finance such acquisitions may put us at a competitive disadvantage for acquiring properties.

We conduct exploration, development and production operations on the deep shelf and in the deepwater of the Gulf of Mexico, which presents unique operating risks.

The deep shelf and the deepwater of the Gulf of Mexico are areas that have had less drilling activity due, in part, to their geological complexity, depth and higher cost to drill and ultimately develop. There are additional risks associated with deep shelf and deepwater drilling that could result in substantial cost overruns and/or result in uneconomic projects or wells. Deeper targets are more difficult to interpret with traditional seismic processing. Moreover, drilling costs and the risk of mechanical failure are significantly higher because of the additional depth and adverse conditions, such as high temperature and pressure. For example, the drilling of deepwater wells requires specific types of rigs with significantly higher day rates, as compared to the rigs used in shallower water. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than development costs for wells drilled on the conventional shelf because deepwater drilling requires larger installation equipment, sophisticated sea floor production handling equipment, expensive state-of-the-art platforms and infrastructure investments. Deep shelf development can also be more expensive than conventional shelf projects because deep shelf development requires more drilling days and higher drilling and service costs due to extreme pressure and temperatures associated with greater depths. Accordingly, we cannot provide assurance that our oil and natural gas exploration activities in the deep shelf, the deepwater and elsewhere will be commercially successful.

Our estimates of future ARO may vary significantly from period to period and are especially significant because our operations are concentrated in the Gulf of Mexico.

We are required to record a liability for the present value of our ARO to plug and abandon inactive non-producing wells, to remove inactive or damaged platforms, and inactive or damaged facilities and equipment, collectively referred to as “idle iron,” and to restore the land or seabed at the end of oil and natural gas production operations. In December 2018, BSEE issued an updated NTL reaffirming the obligations of offshore operators to timely decommission idle iron by means of abandonment and removal. Pursuant to the idle iron NTL requirements, in September 2019, BSEE issued us letters, directing us to plug and abandon certain wells that the agency identified as no longer capable of production in paying quantities by specified timelines, with the earliest deadline being December 31, 2020. In response, we are currently evaluating the list of wells proposed as idle iron by BSEE and currently anticipate that those wells determined to be idle iron will be decommissioned by the specified timelines or at times as otherwise determined by BSEE following further discussions with the agency. While we have established AROs for well decommissioning, additional AROs, significant in amount, may be necessary to conduct plugging and abandonment of the wells designated by BSEE as idle iron but we do not expect the costs to plug and abandon these wells will have a material effect on our financial condition, results of operations or cash flows. Nevertheless, these decommissioning activities are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths, and there exists the possibility that increased liabilities beyond what we established as AROs may arise and the pace for completing these activities could be adversely affected by idle iron decommissioning activities being pursued by other offshore oil and gas lessees that may also have received similar BSEE directives, which could restrict the availability of equipment and experienced workforce necessary to accomplish this work. Estimating future restoration and removal costs in the Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or such requirements may be interpreted more restrictively, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. For example, because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform, from which the work was anticipated to be performed, is damaged or toppled rather than structurally intact. Accordingly, our estimate of future ARO will differ dramatically from our recorded estimate if we have a damaged platform.

The additional requirements under the BOEM’s NTL #2016-N01, if ever fully implemented, would increase our operating costs and reduce the availability of surety bonds due to the increased demands for such bonds in a low-price commodity environment. While the current implementation timeline has been extended indefinitely, except in certain circumstances where there was a substantial risk of nonperformance of the interest holder’s decommissioning liabilities, this timeline could change at the BOEM’s discretion and the BOEM may re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder’s decommissioning liabilities. Under NTL #2016-N01, the BOEM has given broader interpretation authority to the BOEM’s district personnel, which increases the difficulty in complying with this NTL should it be fully implemented. In addition, increased demand for salvage contractors and equipment could result in increased costs for decommissioning activities, including plugging and abandonment operations. These items have, and may further increase our costs and may impact our liquidity adversely.

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

In our contractual arrangements of joint ownership of oil and natural gas interests with other companies, we are obligated to pay our share of operating, capital and decommissioning costs, and have the right to a share of revenues after royalties and certain other cash inflows. If one of the companies in the arrangement is unable to pay its agreed upon share of costs, generally the other companies in the arrangement are obligated to pay the non-paying company’s obligations. Under joint operating agreements among working interest owners, the non-paying company would typically lose the right to future revenues, which would be applied to the non-paying company’s share of operating, capital and decommissioning costs. If future revenues are insufficient to defray these additional costs, especially in cases where the well has stopped producing and is being decommissioned, we could be obligated to pay certain costs of the defaulting party. In addition, the liability to the U.S. Government for obligations of lessees under federal oil and gas leases, including obligations for decommissioning costs, is generally joint and several among the various co-owners of the lease, which means that any single owner may be liable to the U.S. Government for the full amount of all lessees’ obligations under the lease. In certain circumstances, we also could be liable for decommissioning liabilities on federal oil and gas leases that we previously owned and the assignee to whom we assigned the leases or any future assignee of those leases is bankrupt or unable to pay its decommissioning costs. For example, we have in the past received a demand for payment of decommissioning costs related to property interests that were sold several years prior. These indirect obligations would affect our costs, operating profits and cash flows negatively and could be substantial.

We may not be in a position to control the timing of development efforts, associated costs or the rate of production of the reserves from our non-operated properties.

As we carry out our drilling program, we may not serve as operator of all planned wells. In that case, we have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners and our limited ability to influence operations and associated costs of properties operated by others could prevent the realization of anticipated results in drilling or acquisition activities. The success and timing of exploration and development activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

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

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

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

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

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

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

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

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

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

The geographic concentration of our properties in the Gulf of Mexico subjects us to an increased risk of loss of revenues or curtailment of production from factors specifically affecting the Gulf of Mexico.

The geographic concentration of our properties along the U.S. Gulf Coast and adjacent waters on and beyond the OCS means that some or all of our properties could be affected by the same event should the Gulf of Mexico experience:

- severe weather, including tropical storms and hurricanes;
- delays or decreases in production, the availability of equipment, facilities or services;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- delays or decreases in the availability of capacity to transport, gather or process production; and
- changes in the regulatory environment.

Because a majority of our properties could experience the same conditions at the same time, these conditions could have a greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area. For example, during 2019, net production of approximately 2.1 MMBoe was deferred during 2019 due to pipeline issues, maintenance and well issues. During 2018, net production of approximately 1.6 MMBoe was deferred during 2018 due to pipeline issues, maintenance, well issues and other events; and during 2017, net production of approximately 1.7 MMBoe was deferred due to Hurricane Nate, pipeline issues and other events.

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

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

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

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

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

Increasing our reserve base through acquisitions has historically been an important part of our business strategy. We may encounter difficulties integrating the operations of newly acquired oil and natural gas properties or businesses, such as our recent acquisition of the Mobile Bay Properties. 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, 2019. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities*, under Part II, Item 7 for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in *Business* under Part I, Item 1*, Properties* under Part I, Item 2 and *Financial Statements and Supplementary Data – Note 20 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K.

In order to prepare our year-end reserve estimates, our independent petroleum consultant projected our production rates and timing of development expenditures. Our independent petroleum consultant also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be under our control. The process also requires economic assumptions about matters such as crude oil and natural gas prices, operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved oil and natural gas reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month unweighted first-day-of-the-month average price for each product and costs in effect on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Prospects that we decide to drill may not yield oil or natural gas in commercial quantities or quantities sufficient to meet our targeted rates of return.

A prospect is an area in which we own an interest, could acquire an interest or have operating rights, and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic accumulations of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure that the analysis we perform using data from other wells, more fully explored prospects and/or producing fields will accurately predict the characteristics and potential reserves associated with our drilling prospects. Sustained low crude oil, NGLs and natural gas pricing will also significantly impact the projected rates of return of our projects without the assurance of significant reductions in costs of drilling and development. To the extent we drill additional wells in the deepwater and/or on the deep shelf, our drilling activities could become more expensive. In addition, the geological complexity of deepwater and deep shelf formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, we can offer no assurance that we will find commercial quantities of oil and natural gas and, therefore, we can offer no assurance that we will achieve positive rates of return on our investments.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities, which in most cases are owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells because of a reduction in demand for our production or because of inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market. We have, in the past, been required to shut in wells when hurricanes have caused or threatened damage to pipelines and gathering stations. For example, we shut in wells during 2017 from Hurricane Nate and in 2018 from Hurricane Michael for several days.

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, 2019, six fields, accounting for approximately 0.9 MMBoe (or 6.2%) of our 2019 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 reestablish 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 2019 and 2018, various pipelines were shut down at various times causing production deferral of approximately 0.5 MMBoe and 0.4 MMBoe, respectively.

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

We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration, development, production and transportation of crude oil and natural gas and operational safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with such legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- operational reporting;
- reporting of natural gas sales for resale; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well site reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. It is also possible that a portion of our oil and natural gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See *Business – Regulation* under Part I, Item 1 in this Form 10-K for a more detailed explanation of regulations impacting our business.

Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to MPAs and endangered and threatened species.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit or other approval before drilling or other regulated activity commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit exploration or drilling activities on certain lands lying within wilderness, wetlands, MPAs and other protected areas or that may affect certain wildlife, including marine species and endangered and threatened species; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- loss of our leases;
- incurrence of investigatory, remedial or corrective obligations; and
- the imposition of injunctive relief, which could prohibit, limit or restrict our operations in a particular area.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could incur strict joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and regardless of whether our operations met previous standards in the industry at the time they were conducted. Our permits require that we report any incidents that cause or could cause environmental damages.

New laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement could significantly increase our capital expenditures and operating costs or could result in delays, limitations or cancelations to our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. See *Business – Environmental Regulations* under Part I, Item 1 in this Form 10-K for a more detailed description of our environmental, marine species, and endangered and threatened species regulations.

The ONRR's revised interpretations on determining appropriate allowances related to transportation and processing costs for natural gas could cause us to pay substantial amounts in back royalties and in future royalties.

The ONRR has publicly announced an "unbundling" initiative to revise the methodology employed by producers in determining the appropriate allowances for transportation and processing costs that are permitted to be deducted in determining royalties under federal oil and gas leases. The ONRR's initiative requires re-computing allowable transportation and processing costs using revised guidance from the ONRR going back 84 months for every gas processing plant for which we had gas processed. In 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, 2019, we paid $3.1 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.

Our operations are subject to various risks that could result in increasing operating costs, limiting the areas in which oil and natural gas production may occur, and reducing demand for the oil and natural gas that we produce.

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

State implementation of these revised air emission standards could result in stricter permitting requirements, delay, limit or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement for nations to limit their GHG emissions through individually determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in federal political risks in the United States in the form of pledges made by certain candidates seeking the office of the President of the United States in 2020. Critical declarations made by one or more presidential candidates include proposals to ban hydraulic fracturing of oil and natural gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions to oil and natural gas production activities that could be pursued by presidential candidates may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquefied natural gas export facilities, as well as the rescission of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as stockholders and bondholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption of legislation or regulatory programs to reduce or eliminate future 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 or eliminate future emissions of GHG could have an adverse effect on our business, financial condition and results of operations. Additionally, political, financial and litigation risks may result in our restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing the ability to continue to operate in an economic manner. 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 CFTC has finalized most of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules or the timing of such effects.

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, malfunction of our platform control devices, disabling of our communication links, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, violation of privacy or other laws and exposure to litigation. Any of these security breaches could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management, including Tracy W. Krohn, our Founder, Chairman of the Board, Chief Executive Officer and President; Janet Yang, our Executive Vice President and Chief Financial Officer; William J. Williford, our Executive Vice President and General Manager of Gulf of Mexico; Stephen L. Schroeder, our Senior Vice President and Chief Technical Officer; and Shahid A. Ghauri, our Vice President, General Counsel and Corporate Secretary, could have a negative impact on our operations. We do not maintain or plan to obtain for the benefit of the Company any insurance against the loss of any of these individuals. See *Executive Officers of the Registrant* under Part I following Item 3 in this Form 10-K for more information regarding our senior management team.

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 relative to other domestic reservoirs. At December 31, 2019, the following two areas of operations accounted for approximately 67% our proved reserves determined using quantities of proved net reserves on an energy equivalent basis. "Shelf" refers to acreage under 500 feet of water. The following table provides information for these fields:

		Proved Reserves as of December 31, 2019				
	Field Category	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Percent of Total Company Proved Reserves
Mobile Bay Properties	Shelf	0.2	15.4	365.9	76.6	48.7%
Ship Shoal 349 (Mahogany)	Shelf	19.0	2.0	42.2	28.0	17.8%

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

Our Fields

On December 31, 2019, we had two areas of operations of major significance, which we define as having year-end proved reserves of 10% or more of the Company's total proved reserves, calculated on an energy equivalent basis. These areas are the Mobile Bay Properties, which are offshore Alabama but also include the associated gas treatment plant located onshore in Alabama, and the Ship Shoal 349 field (Mahogany) located on the conventional shelf in the Gulf of Mexico. Unless indicated otherwise, "drilling" or "drilled" in the descriptions below refers to when the drilling reached target depth, as this measurement usually has a higher correlation to changes in proved reserves compared to using the SEC's definition for completion. Following are descriptions of these areas of operations:

Mobile Bay Properties

The recently acquired Mobile Bay Properties consist of interests located off the coast of Alabama, in state coastal and federal Gulf of Mexico waters approximately 70 miles south of Mobile, Alabama. The field area includes 16 Alabama state water lease blocks and four Federal OCS lease blocks. These properties include seven major platforms and 27 flowing wells, in up to 50 feet of water. Exxon first discovered Norphlet gas play in 1978 with the first gas production from the Mary Ann Field in 1988. We acquired varied operated working interests ranging from 25% to 100% in nine producing fields from Exxon effective January 1, 2019, and we became the operator of the fields in December 2019. Cumulative field production through 2019 is approximately 576.6 MMBoe gross. The Mobile Bay Properties produce from the Jurassic age Norphlet eolian sandstone at an average depth of 21,000' total vertical depth. As of December 31, 2019, 56 Norphlet wells have been drilled on the Mobile Bay Properties, 45 wells were successful and 27 wells are currently producing.

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

Ship Shoal 349 Field (Mahogany)

Ship Shoal 349 field is located off the coast of Louisiana, approximately 235 miles southeast of New Orleans, Louisiana. The field area covers Ship Shoal federal OCS blocks 349 and 359, with a single production platform on Ship Shoal block 349 in 375 feet of water. Phillips Petroleum Company discovered the field in 1993. We initially acquired a 25% working interest in the field from BP Amoco in 1999. In 2003, we acquired an additional 34% working interest through a transaction with ConocoPhillips that increased our working interest to approximately 59%, and we became the operator of the field in December 2004. In early 2008, we acquired the remaining working interest from Apache Corporation ("Apache") and we now own a 100% working interest in this field except for an interest in one well owned in the Joint Venture Drilling Program. Cumulative field production through 2019 is approximately 53.2 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, 2019, 31 wells have been drilled and 26 were successful. Since acquiring an interest and subsequently taking over as operator, we have directly participated in drilling 17 wells with a 100% success rate. During 2018, one well was completed which had been drilled to target depth during 2017, and in addition, two wells were drilled and completed during 2018. During 2019, one well was drilled, completed and producing in 2019, and significant workover activities were done to increase production.

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,		
	2019	**2018**	**2017**
Net Sales:			
Oil (MBbls)	2,444	1,719	1,896
NGLs (MBbls)	154	167	163
Natural gas (MMcf)	3,955	2,508	2,853
Total oil equivalent (MBoe)	3,257	2,307	2,534
Total natural gas equivalents (MMcfe)	19,545	13,841	15,205
Average daily equivalent sales (Boe/day)	8,925	6,320	6,943
Average daily equivalent sales (Mcfe/day)	53,547	37,920	41,656
Average realized sales prices:			
Oil ($/Bbl)	$ 58.27	$ 62.83	$ 46.64
NGLs ($/Bbl)	21.96	31.14	25.42
Natural gas ($/Mcf)	2.53	3.41	3.16
Oil equivalent ($/Boe)	47.84	52.78	40.08
Natural gas equivalent ($/Mcfe)	7.97	8.80	6.68
Average production costs: (1)			
Oil equivalent ($/Boe)	$ 4.77	$ 4.87	$ 4.30
Natural gas equivalent ($/Mcfe)	0.79	0.81	0.72

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

Volume measurements:

MMBbls – million barrels for crude oil, condensate or NGLs

MMBoe – million barrels of oil equivalent

Bcf – billion cubic feet

Bcfe – billion cubic feet of gas equivalent

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, 2019 are summarized below and the mix by product was 24% oil, 16% NGLs and 60% natural gas determined using the energy-equivalent ratio noted below:

Classification of Proved Reserves (1)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total Energy-Equivalent Reserves (2) Oil Equivalent (MMBoe)	Natural Gas Equivalent (Bcfe)	% of Total Proved	PV-10 (3) (In millions)
Proved developed producing	24.0	20.2	469.2	122.3	734.0	78%	$ 992.0
Proved developed non-producing	4.0	1.5	35.7	11.5	68.9	7%	95.0
Total proved developed	28.0	21.7	504.9	133.8	802.9	85%	1,087.0
Proved undeveloped	9.8	2.8	66.2	23.6	141.6	15%	215.5
Total proved	37.8	24.5	571.1	157.4	944.5	100%	$ 1,302.5

Volume measurements:

MMBbls – million barrels for crude oil, condensate or NGLs

MMBoe – million barrels of oil equivalent

Bcf – billion cubic feet

Bcfe – billion cubic feet of gas equivalent

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2019 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, 2019. Applying this methodology, the West Texas Intermediate ("WTI") average spot price of $55.85 per barrel and the Henry Hub natural gas average spot price of $2.578 per million British Thermal Unit were utilized as the referenced price and after adjusting for quality, transportation, fees, energy content and regional price differentials, the average realized prices were $58.11 per barrel for oil, $18.72 per barrel for NGLs and $2.63 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, of our proved oil and natural gas reserves shown above represent a current market value of our estimated oil and natural gas reserves.

The reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves is as follows (in millions):

	December 31, 2019
Present value of estimated future net revenues (PV-10)	$ 1,302.5
Present value of estimated ARO, discounted at 10%	(184.9)
PV-10 after ARO	1,117.6
Future income taxes, discounted at 10%	(130.7)
Standardized measure of discounted future net cash flows	$ 986.9

Changes in Proved Reserves

Our total proved reserves at December 31, 2019 were 157.4 MMBoe compared to 84.0 MMBoe at December 31, 2018, representing an overall increase of 73.4 MMBoe. Increases from acquisitions were 90.1 MMBoe, primarily from the Mobile Bay Properties; extensions and discoveries were 1.1 MMBoe; and positive technical revisions (including increased well performance) were 7.0 MMBoe. Partially offsetting these increases were decreases due to lower commodity prices of 10.0 MMBoe and production of 14.8 MMBoe. See *Development of Proved Undeveloped Reserves* below for a table reconciling the change in proved undeveloped reserves during 2019. See *Financial Statements and Supplementary Data– Note 20 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

Our estimates of proved reserves, PV-10 and the standardized measure as of December 31, 2019 are calculated based upon SEC mandated 2019 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 2019 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, 2019 included in this Form 10-K was prepared by our independent petroleum consultants, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter included as an exhibit to this Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has been practicing consulting petroleum engineering at NSAI since 2013 and has over 14 years of prior industry experience. NSAI has informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. Additionally, our senior management reviews any significant changes to our proved reserves on a quarterly basis. Our Director of Reservoir Engineering has over 30 years of oil and gas industry experience and has managed the preparation of public company reserve estimates the last 16 years. He joined the Company in 2016 after spending the preceding 12 years as Director of Corporate Engineering for Freeport-McMoRan Oil & Gas. He has also served in various engineering and strategic planning roles with both Kerr-McGee and with Conoco, Inc. He earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1989 and a Master's degree in Business Administration from the University of Houston in 1999.

Reserve Technologies

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our independent petroleum consultant employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as the future prices of crude oil, NGLs and natural gas; and
- the judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered.

Reporting of Natural Gas and Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. We report all natural gas production information net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. We convert barrels to Mcfe using an energy-equivalent ratio of six Mcf to one barrel of oil, condensate or NGLs. This energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for crude oil, NGLs and natural gas may differ substantially.

Development of Proved Undeveloped Reserves

Our PUDs were estimated by NSAI, our independent petroleum consultant. Future development costs associated with our PUDs at December 31, 2019 were estimated at $242.0 million.

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

	December 31,		
	2019	**2018**	**2017**
Proved undeveloped reserves, beginning of year	17.0	12.0	9.3
Transfers to proved developed reserves	(0.5)	(5.0)	(2.3)
Revisions of previous estimates	7.1	11.3	—
Extensions and discoveries	—	—	5.0
Purchase of minerals in place	—	2.2	—
Sales of minerals in place	—	(3.5)	—
Proved undeveloped reserves, end of year	23.6	17.0	12.0

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

Year Scheduled for Development	**Number of PUD Locations**	**Percentage of PUD Reserves Scheduled to be Developed**
2020	3	12%
2021	5	32%
2022	4	56%
Total	12	100%

<u>Activity related to PUDs in 2019:</u>

- Successfully drilled and converted two locations and 0.5 MMBoe from PUD to proved developed with total capital expenditures of $27.1 million during 2019.
- Net PUD revisions of 7.1 MMBoe were primarily at our Ship Shoal 028 and our Mahogany fields.

<u>Activity related to PUDs in 2018:</u>

- Successfully drilled and converted three locations and 5.0 MMBoe from PUD to proved developed with total capital expenditures of $24.5 million during 2018.
- Added eight PUD locations and 11.3 MMBoe primarily at our Ship Shoal 028 and our Mahogany fields.
- Conveyance of a portion of the working interest in properties which included 3.5 MMBoe of PUDs to the Joint Venture Drilling Program, as described in more detail in *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K.

We believe that we will be able to develop all but 2.5 MMBoe (approximately 11%) of the total 23.6 MMBoe classified as PUDs at December 31, 2019, within five years from the date such PUDs were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field ("Matterhorn") and Viosca Knoll 823 ("Virgo") deepwater fields where future development drilling has been planned as sidetracks of existing wellbores due to conductor slot limitations and rig availability. Two sidetrack PUD locations, one each at Matterhorn and Virgo, will be delayed until an existing well is depleted and available to sidetrack. We also plan to recomplete and convert an existing producer at Matterhorn to water injection for improved recovery following depletion of existing well. Based on the latest reserve report, these PUD locations are expected to be developed in 2021 and 2022.

Acreage

The following table summarizes our leasehold at December 31, 2019. Deepwater refers to acreage in over 500 feet of water:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	455,944	319,495	137,557	119,487	593,501	438,982
Deepwater	159,209	58,899	61,971	49,683	221,180	108,582
Total	615,153	378,394	199,528	169,170	814,681	547,564

Approximately 69% 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, 1,152 net acres (1%) of the total 169,170 net undeveloped acres could expire in 2020; 5,760 net acres (3%) could expire in 2021; 7,210 net acres (4%) could expire in 2022; 66,936 net acres (40%) could expire in 2023; and 88,112 net acres (52%) could expire in 2024 and beyond. In making decisions regarding drilling and operations activity for 2020 and beyond, we give consideration to undeveloped leasehold that may expire in the near term in order that we might retain the opportunity to extend such acreage.

Our net acreage increased 153,120 net acres (39%) from December 31, 2018 due to acquisitions and lease purchases, partially offset by sales, lease expirations and relinquishments.

Production

For the years 2019, 2018 and 2017, our net daily production averaged 40,634 Boe, 36,510 Boe and 39,921 Boe, respectively. Production increased in 2019 from 2018 primarily due to the acquisition of the Mobile Bay Properties, increases at Mahogany from drilling and workovers, and wells coming online at other fields, partially offset by natural production declines. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations* under Part II, Item 7 in this Form 10-K for additional information.

The following presents historical information about our produced oil, NGLs and natural gas volumes from all of our producing fields over the past three years:

	Year Ended December 31,		
	2019	2018	2017
Net Sales:			
Oil (MBbls)	6,675	6,687	7,064
NGLs (MBbls)	1,271	1,307	1,382
Oil and NGLs (MBbls)	7,946	7,994	8,446
Natural gas (MMcf)	41,310	31,991	36,754
Total oil equivalent (MBoe)	14,831	13,326	14,571
Total natural gas equivalents (MMcfe)	88,987	79,956	87,428

Volume measurements:

MBbls – thousand barrels for crude oil, condensate or NGLs

MBoe – thousand barrels of oil equivalent

MMcf – million cubic feet

MMcfe – million cubic feet equivalent

See *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, 2019 in our productive oil and natural gas wells. A net well represents our fractional working interest of a gross well in which we own less than all of the working interest:

Offshore Wells	Oil Wells (1)		Gas Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	96	82.3	81	68.2	177	150.5
Non-operated	37	8.3	26	8.7	63	17.0
Total offshore wells	133	90.6	107	76.9	240	167.5

(1) Includes seven gross (6.0 net) oil wells with multiple completions.

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

Drilling Activity

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

Development and Exploration Drilling

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

	Year Ended December 31,		
	2019	2018	2017
Development Wells Completed:			
Gross wells	3.0	3.0	3.0
Net wells	1.6	1.5	3.0
Exploration Wells Completed:			
Gross wells	3.0	3.0	1.0
Net wells	0.8	1.3	0.8

Our success rates related to our development and exploration wells drilled was 100% in both 2019 and 2018, with all wells drilled being productive and none were non-commercial (dry holes). In 2017, we drilled one sub-sea well which had not been completed as of the filing date of this Form 10-K as we are evaluating various options on this well. As such, we have not reflected the well in the table above. Of the remaining wells in our 2017 drilling program, 80% of the wells drilled were productive and we had one exploration well drilled during 2017 that was deemed to be non-commercial and therefore not completed, of which we had a 39% working interest.

Recent Drilling Activity

During 2019, the following wells were completed: the Virgo A-13 exploration well; the South Timbalier 320 A-3 development well; the Mississippi Canyon 800 ("Gladden") SS002 exploration well; the Ship Shoal 028 041 development well; the East Cameron 321 B-8 ST1 development well; and the Mahogany A-6 ST1 development well. All of these wells are in the Joint Venture Drilling Program except for the Mahogany A-6 ST1 well. During the first two months of 2020, there was one well in the process of drilling, which is in the Joint Venture Drilling Program.

Capital Expenditures

See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Expenditures* under Part II, Item 7 in this Form 10-K for capital expenditure information.

Item 3. ***Legal Proceedings***

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

Appeal with ONRR. In 2009, we recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited our calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance with the offset to a liability reserve; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the Interior Board of Land Appeals ("IBLA") under the DOI. On January 27, 2017, the IBLA affirmed the decision of the ONRR requiring W&T to pay approximately $4.7 million in additional royalties. We filed a motion for reconsideration of the IBLA decision on March 27, 2017. Based on a statutory deadline, we filed an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana. We were required to post a bond in the amount of $7.2 million and cash collateral of $6.9 million in order to appeal the IBLA decision. On December 4, 2018, the IBLA denied our motion for reconsideration. On February 4, 2019, we filed our first amended complaint, and the government has filed its Answer in the Administrative Record. On July 9, 2019, we filed an Objection to the Administrative Record and Motion to Supplement the Administrative Record, asking the court to order the government to file a complete privilege log with the record. Following a hearing on July 31, 2019, the Court ordered the government to file a complete privilege log. In an Order dated December 18, 2019, the court ordered the government to produce certain contracts subject to a protective order and to produce the remaining documents in dispute to the court for *in camera* review. We are waiting for the results of that review. Once the issues concerning the administrative record are resolved, the parties will file cross-motions for summary judgment. In January 2020, the cash collateral in the amount of $6.9 million securing the appeal bond in this matter was released to us.

Royalties-In-Kind ("RIK"). Under a program of the Minerals Management Service ("MMS") (a DOI agency and predecessor to the ONRR), royalties must be paid "in-kind" rather than in value from federal leases in the program. The MMS added to the RIK program our lease at the East Cameron 373 field beginning in November 2001, where in some months we over delivered volumes of natural gas and under delivered volumes of natural gas in other months for royalties owed. The MMS elected to terminate receiving royalties in-kind in October 2008, causing the imbalance to become fixed for accounting purposes. The MMS ordered us to pay an amount based on its interpretation of the program and its calculations of amounts owed. We disagreed with MMS's interpretations and calculations and filed an appeal with the IBLA, of which the IBLA ruled in MMS' favor. We filed an appeal with the District Court of the Western District of Louisiana, who assigned the case to a magistrate to review and issue a ruling, and the District Court upheld the magistrate's ruling on May 29, 2018. We filed an appeal on July 24, 2018. Part of the ruling was in favor of our position and part was in favor of MMS' position. We appealed the ruling to the U.S. Fifth Circuit Court of Appeals and the government filed a cross-appeal. The Fifth Circuit issued its ruling on December 23, 2019, holding that, while the DOI has statutory authority to switch the method of royalty payment from volumes ("in-kind") to cash ("in value"), the "cashout" methodology that the DOI ordered W&T to implement was unenforceable because that methodology was a "substantive rule" that the DOI adopted in violation of the Administrative Procedure Act. In addition, the Fifth Circuit held that the DOI's claim was unlawfully inflated because DOI improperly failed to give W&T credit for all royalty volumes delivered. The Fifth Circuit remanded the case to the district court to implement the court's decision on appeal. Based on the combination of (i) the DOI's concessions concerning the scope of W&T's liability (e.g., that W&T is only liable for its working interest share of the royalty volumes at issue), and (ii) the Fifth Circuit's ruling, we estimate that the value of the DOI's claim against W&T is no greater than $0.25 million.

Monetary Sanctions by Government Authorities (Notices of Proposed Civil Penalty Assessment). During 2019 and 2018, we did not pay any civil penalties to the BSEE related to Incidents of Noncompliance ("INCs") at various offshore locations. We currently have nine open civil penalties issued by the BSEE from INCs, which have not been settled as of the filing date of this Form 10-K. The INCs underlying these open civil penalties cite alleged non-compliance with various safety-related requirements and procedures occurring at separate offshore locations on various dates ranging from July 2012 to January 2018. The proposed civil penalties for these INCs total $7.7 million. As of December 31, 2019 and December 31, 2018, we have accrued approximately $3.5 million, which is our estimate of the final settlements once all appeals have been exhausted. We believe the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

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

See *Financial Statements and Supplementary Data - Note 18 – Contingencies* under Part II, Item 8 in this Form 10-K for additional information on the matters described above.

Executive Officers of the Registrant

The following table lists our executive officers:

Name	Age (1)	Position
Tracy W. Krohn	65	Chairman, Chief Executive Officer and President
Janet Yang	39	Executive Vice President and Chief Financial Officer
William J. Williford	47	Executive Vice President and General Manager of Gulf of Mexico
Stephen L. Schroeder	57	Senior Vice President and Chief Technical Officer
Shahid A. Ghauri	51	Vice President, General Counsel and Corporate Secretary

(1) Ages as of February 23, 2020

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

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

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

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

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

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

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

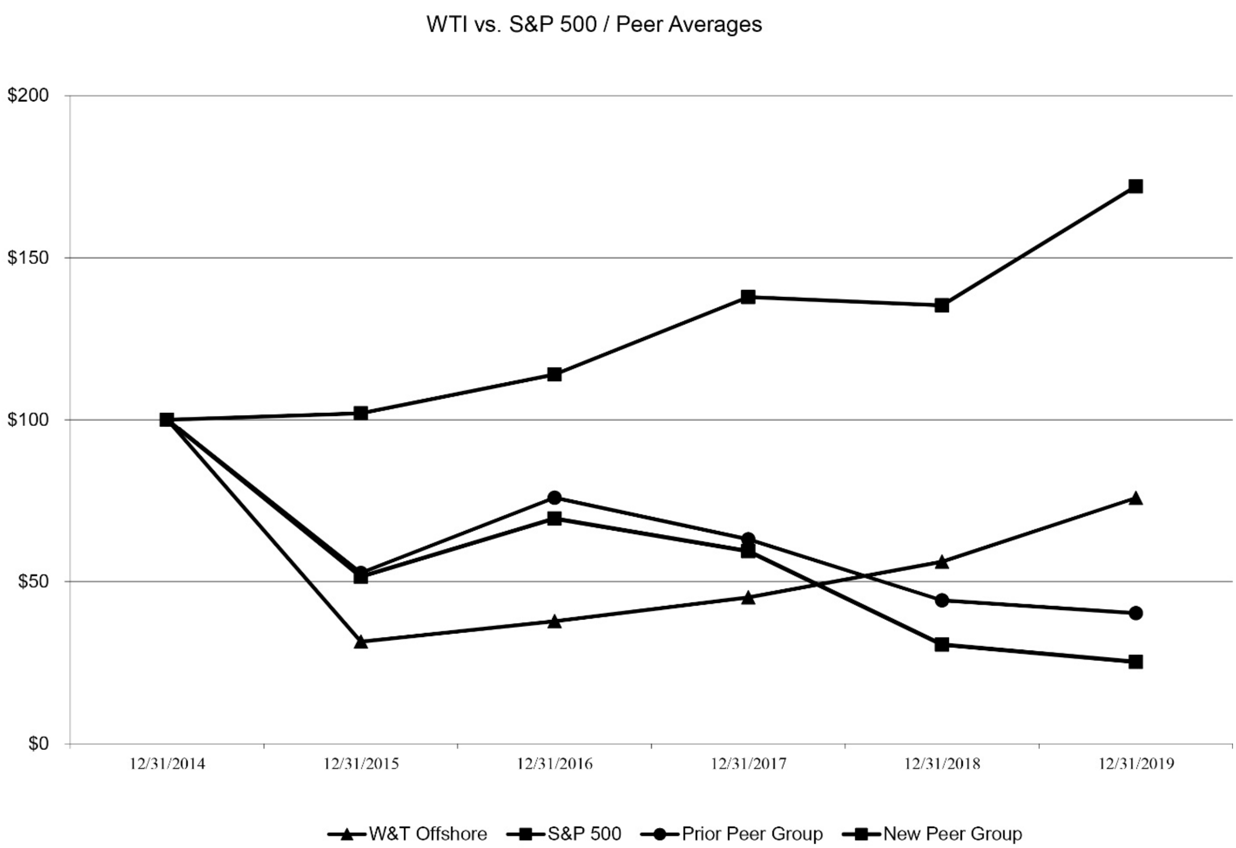
Our common stock is listed and principally traded on the NYSE under the symbol "WTI." As of March 2, 2020, there were 178 registered holders of our common stock.

Dividends

During 2019 and 2018, no dividends were paid as dividend payments have been suspended. Our Board of Directors decides the timing and amounts of any dividends for the Company. Dividends are subject to periodic review of the Company's performance, which includes the current economic environment and applicable debt agreement restrictions. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 and *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for more information regarding covenants related to dividends in our debt agreements.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 in our common stock and the reinvestment of all dividends thereafter. The information contained in the graph below is furnished and not filed, and is not incorporated by reference into any document that incorporates this Form 10-K by reference.



Our peer group was revised in 2019 ("New Peer Group") to be in alignment with the peer group used for executive compensation analysis and the prior peer group was reduced through mergers and acquisitions to only four companies. The New Peer Group is comprised of: Abraxas Petroleum Corporation; Bonanza Creek Energy Inc.; Comstock Resources, Inc.; Earthstone Energy Inc.; Gran Tierra Energy Inc.; Gulfport Energy Corporation; Highpoint Resources Corporation; Kosmos Energy Ltd.; Laredo Petroleum, Inc.; Northern Oil and Gas, Inc.; and Ring Energy, Inc. Companies used in the most recent executive compensation analysis but were excluded due to not having a five year trading history were Talos Energy, Inc. and Extraction Oil and Gas, Inc. The prior peer group ("Prior Peer Group") was comprised of: Apache Corporation; Cabot Oil & Gas Corp.; Comstock Resources, Inc.; and SM Energy Co. Excluded from the prior peer group in the above graph was Newfield Exploration Co., as their stock was not traded during all of 2019 due to being acquired by Encana Corporation.

Securities Authorized for Issuance under Equity Compensation Plans

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K. For descriptions of the plans and additional information, see *Financial Statements and Supplementary Data – Note 11 –Share-Based Awards and Cash-Based Awards* under Part II, Item 8 in this Form 10-K.

Issuer Purchases of Equity Securities

For the year 2019, we did not purchase any of our equity securities.

The following table sets forth information about restricted stock units ("RSUs") during the quarter ended December 31, 2019:

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, 2019 – October 31, 2019	N/A	N/A	N/A	N/A
November 1, 2019 – November 30, 2019	N/A	N/A	N/A	N/A
December 1, 2019 – December 31, 2019 (1)	496,824	$ 4.72	N/A	N/A

(1) RSUs delivered by employees during December 2019 to satisfy tax withholding obligations on the vesting of RSU.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2019 that we have not previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

Item 6. Selected Financial Data

SELECTED HISTORICAL FINANCIAL INFORMATION

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

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(In thousands, except per share data)				
Consolidated Statement of Operations Information:					
Revenues:					
Oil	$ 399,790	$ 438,798	$ 340,010	$ 268,950	$ 349,191
NGLs	22,373	37,127	32,257	26,429	27,665
Natural gas	106,347	99,629	108,923	100,405	123,435
Other	6,386	5,152	5,906	4,202	6,974
Total revenues	534,896	580,706	487,096	399,986	507,265
Operating costs and expenses:					
Lease operating expenses	184,281	153,262	143,738	152,399	192,765
Production taxes	2,524	1,832	1,740	1,889	3,002
Gathering and transportation	25,950	22,382	20,441	22,928	17,157
Depreciation, depletion and amortization	129,038	131,423	138,510	194,038	373,368
Asset retirement obligations accretion	19,460	18,431	17,172	17,571	20,703
Ceiling test write-down of oil and natural gas properties	—	—	—	279,063	987,238
General and administrative expenses	55,107	60,147	59,744	59,740	73,110
Derivative loss (gain)	59,887	(53,798)	(4,199)	2,926	(14,375)
Total costs and expenses	476,247	333,679	377,146	730,554	1,652,968
Operating income (loss)	58,649	247,027	109,950	(330,568)	(1,145,703)
Interest expense, net	59,569	48,645	45,521	84,382	97,205
Gain on debt transactions	—	47,109	7,811	123,923	—
Other expense (income), net	188	(3,871)	5,127	1,369	4,794
(Loss) income before income tax (benefit) expense	(1,108)	249,362	67,113	(292,396)	(1,247,702)
Income tax (benefit) expense	(75,194)	535	(12,569)	(43,376)	(202,984)
Net income (loss)	$ 74,086	$ 248,827	$ 79,682	$ (249,020)	$ (1,044,718)
Basic and diluted earnings (loss) per common share	$ 0.52	$ 1.72	$ 0.56	$ (2.60)	$ (13.76)

SELECTED HISTORICAL FINANCIAL INFORMATION
(continued)

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(In thousands)				
Consolidated Cash Flow Information:					
Net cash provided by (used in) operating activities	$ 232,227	$ 321,763	$ 159,408	$ 14,180	$ 133,228
Net cash (used in) provided by investing activities	(313,814)	(66,385)	(107,107)	(82,396)	86,075
Net cash provided by (used in) financing activities	80,727	(321,143)	(23,479)	53,038	(157,555)

	December 31,				
	2019	2018	2017	2016	2015
	(In thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 32,433	$ 33,293	$ 99,058	$ 70,236	$ 85,414
Oil and natural gas properties and other, net (1)	748,798	515,421	579,016	547,053	990,049
Total assets (1)	1,003,719	848,866	907,580	829,726	1,208,022
Long-term debt (including current portion)	719,533	633,535	992,052	1,020,727	1,196,855
Shareholders' deficit (1)	(249,365)	(324,796)	(573,508)	(659,037)	(526,491)

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

HISTORICAL RESERVE AND OPERATING INFORMATION

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

	December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
Reserve Data: (1)					
Estimated net proved reserves					
Oil (MMBbls)	37.8	39.1	34.4	32.9	35.5
NGLs (MMBbls)	24.5	9.8	7.8	8.2	6.6
Natural Gas (Bcf)	571.1	210.5	192.2	197.8	205.4
Total barrel equivalents (MMBoe)	157.4	84.0	74.2	74.0	76.4
Total natural gas equivalents (Bcfe)	944.5	504.1	445.3	444.0	458.1
Proved developed producing (MMBoe)	122.3	53.9	54.5	47.3	57.6
Proved developed non-producing (MMBoe)	11.5	13.1	7.7	17.4	11.4
Total proved developed (MMBoe)	133.8	67.0	62.2	64.7	69.0
Proved undeveloped (MMBoe)	23.6	17.0	12.0	9.3	7.4
Proved developed reserves as %	85.0%	79.8%	83.8%	87.4%	90.3%
Reserve additions (reductions) (MMBoe):					
Revisions (2)	(3.0)	21.1	9.6	13.0	(12.7)
Extensions and discoveries	1.1	2.1	5.2	—	4.1
Purchases of minerals in place	90.1	3.4	—	—	1.0
Sales of minerals in place (3)	—	(3.5)	—	—	(19.0)
Production	(14.8)	(13.3)	(14.6)	(15.4)	(17.0)
Net reserve additions (reductions)	73.4	9.8	0.2	(2.4)	(43.6)

(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 2019 include estimated price revisions for all proved reserves and incorporate the impact of price change of the purchase of minerals in place from the date of purchase to December 31, 2019. Revisions in 2015 also include revisions related to the Yellow Rose field up to the date of the sale.

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

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

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

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Operating: (1)					
Net sales:					
Oil (MBbls)	6,675	6,687	7,064	7,201	7,751
NGLs (MBbls)	1,271	1,307	1,382	1,542	1,604
Oil and NGLs (MBbls)	7,946	7,994	8,446	8,743	9,355
Natural gas (MMcf)	41,310	31,991	36,754	39,731	46,163
Total oil equivalent (MBoe)	14,831	13,326	14,571	15,365	17,049
Total natural gas equivalents (MMcfe)	88,987	79,956	87,428	92,188	102,294
Average daily equivalent sales (Boe/day)	40,634	36,510	39,921	41,980	46,709
Average daily equivalent sales (Mcfe/day)	243,801	219,057	239,528	251,879	280,256
Average realized sales prices:					
Oil ($/Bbl)	$ 59.89	$ 65.62	$ 48.13	$ 37.35	$ 45.05
NGLs ($/Bbl)	17.60	28.40	23.35	17.14	17.25
Oil and NGLs ($/Bbl)	53.13	59.53	44.08	33.79	40.28
Natural gas ($/Mcf)	2.57	3.11	2.96	2.53	2.67
Oil equivalent ($/Boe)	35.63	43.19	33.02	25.76	29.34
Natural gas equivalent ($/Mcfe)	5.94	7.20	5.50	4.29	4.89
Average per Boe ($/Boe):					
Lease operating expenses	$ 12.43	$ 11.50	$ 9.86	$ 9.92	$ 11.31
Gathering and transportation	1.75	1.68	1.40	1.49	1.01
Production costs	14.18	13.18	11.26	11.41	12.32
Production taxes	0.17	0.14	0.12	0.12	0.17
DD&A (2)	10.01	11.24	10.68	13.77	23.11
General and administrative expenses	3.72	4.51	4.10	3.89	4.29
	$ 28.08	$ 29.07	$ 26.16	$ 29.19	$ 39.89
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 2.07	$ 1.92	$ 1.64	$ 1.65	$ 1.88
Gathering and transportation	0.29	0.28	0.23	0.25	0.17
Production costs	2.36	2.20	1.87	1.90	2.05
Production taxes	0.03	0.02	0.02	0.02	0.03
DD&A (2)	1.67	1.87	1.78	2.30	3.85
General and administrative expenses	0.62	0.75	0.68	0.65	0.71
	$ 4.68	$ 4.84	$ 4.35	$ 4.87	$ 6.64
Wells drilled (gross) (3)	6	6	5	1	5
Productive wells drilled (gross) (3)	6	6	4	1	5

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

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

(3) Wells drilled in the above table are all offshore wells. Onshore wells drilled in 2015 are omitted as the Company divested its interest in onshore wells.

Volume measurements:

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

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

The following discussion and analysis should be read in conjunction with *Financial Statements and Supplementary Data* under Part II, Item 8 in this Form 10-K. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in *Risk Factors* under Part I, Item 1A in this Form 10-K.

Overview

We are an independent oil and natural gas producer, active in the exploration, development and acquisition of oil and natural gas properties in the Gulf of Mexico. We have grown through acquisitions, exploration and development and currently hold working interests in 51 offshore producing fields in federal and state waters. We currently have under lease approximately 815,000 gross acres (550,000 net acres) spanning across the OCS off the coasts of Louisiana, Texas, Mississippi and Alabama, with approximately 595,000 gross acres on the conventional shelf and approximately 220,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. We currently own interests in 146 offshore structures, 104 of which are located in fields that we operate. We currently own interest in 240 productive wells, 177 of which we operate. Our interest in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. and our wholly-owned subsidiary, W & T Energy VI, LLC, a Delaware limited liability company and through our proportionately consolidated interest in Monza, as described in more detail in *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K.

In recent years, we have operated or participated in wells near the outer edge of the OCS and in the deepwater of the Gulf of Mexico. To the extent we expand our deepwater operations, our operating and ARO costs may increase, especially as we find and produce more crude oil rather than natural gas. Our offshore operations are exposed to potential damage from hurricanes and we normally obtain insurance to reduce, but not totally mitigate, our financial exposure risk. See *Liquidity and Capital Resources – Insurance Coverage* under this Item 7 in this Form 10-K for additional information. We are subject to a number of regulations from federal and state governmental entities, which are described under Part,I, Item 1, *Regulations* in this Form 10-K. Our Company and others like us, are exposed to a number of risks by operating in the oil and gas industry in the Gulf of Mexico, which are described in Item 1A, *Risk Factors,* in this Form 10-K.

In managing our business, we are focused on optimizing production and increasing reserves in a profitable and prudent manner, while managing cash flows to meet our obligations and investment needs. Our cash flows are materially impacted by the prices of commodities we produce (crude oil and natural gas, and the NGLs extracted from the natural gas). In addition, the prices of goods and services used in our business can vary and impact our cash flows. During 2019, average realized commodity prices decreased from those we experienced during 2018 but were higher from those we experienced during 2017. Our margins in 2019 decreased from 2018 primarily due to lower average realized commodity prices. We measure margins using Adjusted EBITDA as a percent of revenue, which is a not a financial measurement under GAAP. We have historically increased our reserves and production through acquisitions, our drilling programs, and other projects that optimize production on existing wells. Our production increased 11.3% in 2019 from the prior year and we added 73.4 MMBoe of proved reserves in 2019, almost doubling our proved reserves and replacing our production by six times. The 87% net increase in proved reserves year-over-year is primarily due to our acquisition of the Mobile Bay Properties (discussed below), as well as successful drilling, favorable technical revisions driven by improved well performance, recompletion, and workover efforts. Partially offsetting these increases were decreases in proved reserves from lower commodity prices and production. During 2019, we drilled and completed six additional wells which all began producing during 2019.

In August 2019, we acquired the Mobile Bay Properties with the purchase of Exxon's interests in and operatorship of oil and gas producing properties in the eastern region of the Gulf of Mexico offshore Alabama and related onshore and offshore facilities and pipelines. After taking into account customary closing adjustments and an effective date of January 1, 2019, cash consideration was $169.8 million, of which substantially all was paid by us at closing. We also assumed the related ARO and certain other obligations associated with these assets. The acquisition was funded from cash on hand and borrowings of $150.0 million under the Credit Agreement, which were previously undrawn. As of December 31, 2019, the Mobile Bay Properties had approximately 76.6 MMBoe of net proved reserves, of which 99% were proved developed producing reserves consisting primarily of natural gas and NGLs with 20% of the proved net reserves from liquids on a MMBoe basis, based on SEC pricing methodology. For the fourth quarter of 2019, the average production of the Mobile Bay Properties was approximately 18,500 net Boe per day. The properties include working interests in nine Gulf of Mexico offshore producing fields and an onshore treatment facility that are adjacent to existing properties owned and operated by us. With this purchase, we became the largest operator in the area.

During 2019, the percentage of our production from our fields on the conventional shelf increased to 73% in 2019 from 59% in 2018 of our total production (measured on an MMBoe basis) primarily due to acquisition of the Mobile Bay Properties and increases in production at the Mahogany field. In the fourth quarter of 2019, which included the Mobile Bay Properties' production for the entire quarter, the percentage of our production from our fields on the conventional shelf increased to 79% measured on an MMBoe basis. The Mobile Bay Properties accounted for 35% of our production measured on an MMBoe basis in the fourth quarter of 2019.

Based on a reserve report prepared by NSAI, our independent petroleum consultants, our total proved reserves at December 31, 2019 were 157.4 MMBoe compared to 84.0 MMBoe as of December 31, 2018. Approximately 78% of our proved reserves as of December 31, 2019 were classified as proved developed producing, 7% as proved developed non-producing and 15% as proved undeveloped. Classified by product, our proved reserves at December 31, 2019 were 24% crude oil, 16% NGLs and 60% natural gas. These percentages and other energy-equivalent measurements stated in this Form 10-K were determined using the industry standard energy-equivalent ratio of six Mcf of natural gas to one 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 PV-10 of $1,302.5 million before consideration of cash outflows related to ARO. Our PV-10 after considering future cash outflows related to ARO was $1,117.6 million, and our standardized measure of discounted future cash flows was $986.9 million as of December 31, 2019. Neither PV-10 nor PV-10 after ARO is a financial measure defined under GAAP. For additional information about our proved reserves and a reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 in this Form 10-K.

To provide additional financial flexibility, we created the Joint Venture Drilling Program with private investors during 2018 and completed nine drilling projects by the end of 2019. The Joint Venture Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in certain drilling projects. It also allows more projects to be taken on with our capital expenditures budget, thereby helping us reduce our level of concentration risk via diversification. In the Joint Venture Drilling Program, five wells came on line during 2019 and four wells came on line during 2018. For the first half of 2020, two wells are scheduled to be drilled and, assuming success, the wells are expected to start producing in late 2020 or early 2021. See *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K for additional information on the Joint Venture Drilling Program.

In October 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, we issued $625.0 million of Senior Second Lien Notes, which were issued at par with an interest rate of 9.75% per annum that matures on November 1, 2023. Concurrently, we renewed our credit facility by entering into the Credit Agreement, which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million. The borrowing base is subject to scheduled semi-annual redeterminations to occur around May 15 and November 14 each calendar year, and certain additional redeterminations that may be requested at the discretion of either the lenders or the Company. The borrowing base remained at $250.0 million as of December 31, 2019 following the latest redetermination. See *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for a full description of the transaction and the new debt instruments.

As of December 31, 2019, we had $32.4 million of available cash and $139.2 million available under our Credit Agreement, which currently has a borrowing base of $250.0 million. See the *Liquidity and Capital Resources* section of this Item 7, and *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for a description of our debt structure.

For 2019, cash used for investing activities related to acquisitions and capital expenditures were $313.8 million compared to $123.0 million in 2018 (excluding proceeds from sales), which increased primarily due to the acquisition of the Mobile Bay Properties. For 2017, cash used for investing activities related to capital expenditures was $107.1 million, which had no significant acquisitions. Our preliminary capital expenditure budget for 2020 has been established in the range of $50.0 million to $100.0 million, which includes our share of the Joint Venture Drilling Program, and excludes acquisitions. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments. We have flexibility in our capital expenditure programs as we have no long-term rig commitments and our current commitments with partners are short term. Some of our expenditures incurred during 2019 impacted our production for 2019, but most of the impact is expected to occur in 2020 and beyond. In addition, we spent $11.4 million in 2019 and $28.6 million in 2018 for ARO and plan to spend in the range of $15.0 million to $25.0 million in 2020 for ARO.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for 2019 were comprised of approximately 45% oil and condensate, 9% NGLs and 46% natural gas, determined using the energy-equivalent ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs. The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices per Mcfe for crude oil, NGLs and natural gas may differ significantly. For 2019, our combined total production of oil, NGLs and natural gas was 11.3% above 2018, primarily due to the acquisition of the Mobile Bay Properties and increases at our Mahogany field.

Our realized sales prices received for our crude oil, NGLs and natural gas production are affected by not only domestic production activities and political issues, but more importantly, international events, including both geopolitical and economic events. During 2019, crude oil, NGLs and natural gas average realized prices were below 2018 realized prices, decreasing 8.7%, 38.0% and 17.4%, respectively.

Our operating costs in 2019 include the expense of operating our wells, platforms and other infrastructure primarily in the Gulf of Mexico. These operating costs are comprised of several components, including direct or base lease operating costs, facility repairs and maintenance, workover costs, insurance premiums, and gathering and transportation costs. During 2019, our lease operating expenses increased 20.2% compared to 2018 on an absolute basis. The increase was primarily due to incurring operating costs associated with the Mobile Bay Properties acquisition and a full year of operating costs for the Heidelberg field acquisition consummated during 2018. Our operating costs depend in part on the type of commodity produced, the level of workover activity and the geographical location of the properties. Workover costs can vary significantly from year to year depending on the level of activity (either required or desired) and type of equipment used. In those instances where a drilling rig is required as opposed to some other type of intervention vessel or equipment, the costs tend to be higher and require more time.

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

As reported by the U.S. Energy Information Administration ("EIA") in their Short-Term Energy Outlook issued in February 2020 ("STEO"), worldwide production of petroleum and other liquids was estimated to have no increase in 2019 over the prior year, which was lower than the year-over-year production growth experienced from the last two years of 3.1% for 2018 and 0.5% for 2017. The flat growth was due primarily to increases in the U.S. being offset by decreases at OPEC, who has recently announced production cuts. Consumption for 2019 increased 0.7% over 2018 with China having the largest increase year-over-year.

EIA's forecasts for production, consumption, crude oil prices and natural gas prices for 2020 were revised downward in February 2020 from the forecast provided in January 2020 to reflect the effects of the coronavirus and the warmer-than-normal January temperatures across the northern hemisphere. The EIA forecasts worldwide production of petroleum and other liquids year-over-year increases for 2020 and 2021 to be 1.3% and 1.0%, respectively. The expected increase is due primarily to increases in production in the U.S. and partially offset by decreases for OPEC. Consumption for 2020 and 2021 is estimated to increase year-over-year by 1.0% and 1.5%, respectively, with China accounting for the largest category increase.

According to EIA, U.S. crude oil production (excluding other petroleum liquids) increased 11.7% in 2019 over 2018, and is expected to increase year-over-year in 2020 and 2021 by 7.8% and 2.7%, respectively. For the U.S., net imports of crude oil in the U.S. fell by 33.4% in 2019 compared to 2018 and are expected to increase by 1.0% in 2020 from 2019. EIA estimates that the U.S. has exported more crude oil and petroleum products than it has imported since September 2019.

Geopolitical events could greatly affect the prices for crude oil, natural gas and other petroleum products. While these events are difficult to predict, countries like Venezuela, Nigeria, Libya, and many Middle East countries have had, and could continue to have, disruptions due to political and economic factors outside of production issues, with an example being the attacks on Saudi Arabia's oil infrastructure in September 2019. Venezuela's production in 2019 decreased and is expected to continue to fall. Nigeria and Libya's production increased during 2019.

The two primary benchmarks for our average realized crude oil sales prices are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $56.98 per barrel for 2019, down from $65.23 barrel for 2018 (12.6% decrease). Brent crude oil prices averaged $64.28 per barrel for 2019, down from $71.34 per barrel for 2018 (9.9% decrease). The EIA projects average crude oil prices for WTI to decrease approximately $1.00 per barrel in 2020 compared to 2019, and increase in 2021 by approximately $6.00 per barrel. Brent prices are estimated to decrease approximately $3.00 per barrel in 2020 compared to 2019, and to increase approximately $6.00 per barrel in 2021 EIA did not revise their price forecasts for the year 2021 in their latest STEO.

For 2019, our average realized crude oil sales price was $59.89 per barrel. Our average realized crude oil sales price differs from the WTI benchmark average crude price due primarily to premiums or discounts, crude oil quality adjustments, volume weighting (collectively referred to as differentials) and other factors. Crude oil quality adjustments can vary significantly by field. For example, crude oil from our East Cameron 321 field normally receives a positive quality adjustment, whereas crude oil from our Mahogany field normally receives a negative quality adjustment. All of our crude oil is produced offshore in the Gulf of Mexico and is characterized as Poseidon, Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS") and others. WTI is frequently used to value domestically produced crude oil, and the majority of our crude oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. Similar to crude oil prices, the differentials for our offshore crude oil have also experienced volatility in the past. The monthly average differentials of WTI versus Poseidon, LLS and HLS for 2019 improved on average by approximately $1.00 - $2.00 per barrel compared to 2018 for these types of crude oils with all three having positive differentials as measured on an index basis.

During 2019, our average realized NGLs sales price per barrel decreased by 38.0% compared to 2018. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During 2019, average prices for domestic ethane decreased by 38% and average domestic propane prices decreased by 39% from 2018 as measured using a price index for Mount Belvieu. The changes in the average price for other domestic NGLs components in 2019 ranged from a decrease of 19% to 36% year-over-year. Per EIA, production of ethane increased 7% in 2019 compared to 2018 and is expected to increase year-over-year by 16% and 10% for 2020 and 2021, respectively. Propane production increased 14% in 2019 compared to 2018 and is expected to increase year-over-year by 8% for 2020 and decrease 3% for 2021. Ethane and propane inventories increased 13% and 30%, respectively as of December 31, 2019 compared to December 31, 2018. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Propane usage is affected by weather as it is used for house heating fuel in certain areas and for crop drying, along with other uses. Heating degree days were approximately flat in 2019 compared to 2018.

During 2019, our average realized natural gas sales price decreased 17.4% compared to 2018. According to data from EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 18.7% lower in 2019 compared to 2018. Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. Natural gas inventories at the end of January 2020 were 9% above the five-year average for the previous five years. EIA projects natural gas supply to be greater than consumption in 2020 and forecasts Henry Hub spot prices to drop by 14% year-over-year to $2.29 per Mcf.

EIA reports that electrical power generation sourced by natural gas consumption increased to 37% in 2019 compared to 35% in 2018 and forecasts this percentage to remain at this level in 2020 and 2021. The percentage of electrical power generation sourced from coal fell in 2019 to 24% compared to 27% 2018 and is expected to decrease further in 2020 and 2021 to 22% and 21%, respectively. The percentage of electrical power sourced from renewable sources, such as hydropower and wind, increased to 17.4% in 2019 as compared to 17.1% in 2018 and is forecast to exceed 21% by 2021.

According to Baker Hughes, as of December 31, 2019, the number of working rigs drilling for oil and natural gas in the U.S. was lower than 2018 levels and reported 805 working rigs as of December 2019 compared to 1,083 working rigs as of December 2018. The oil rig count at the end of December 2019 and December 2018 was 677 and 885, respectively. The U.S. natural gas rig count at the end of December 2019 and December 2018 was 125 and 198, respectively. In the Gulf of Mexico, the number of working rigs was 23 rigs (22 oil and one natural gas rig) at the end of December 2019 and 24 rigs (20 oil and four natural gas rigs) at the end of December 2018.

Business Strategy

Our goal is to pursue high rate of return projects and develop oil and natural gas resources that allow us to grow our production, reserves and cash flow in a capital efficient manner, thus enhancing the value of our assets. We intend to execute the following elements of our business strategy in order to achieve this goal:

- Exploiting existing and acquired properties to add additional reserves and production;
- Exploring for reserves on our extensive acreage holdings and in other areas of the Gulf of Mexico;
- Acquiring reserves with substantial upside potential and additional leasehold acreage complementary to our existing acreage position at attractive prices; and
- Continuing to manage our balance sheet in a prudent manner and continuing our track record of financial flexibility in any commodity price environment. Over time, we expect to de-lever through free cash flow generated by our producing asset base, capital discipline, organic growth and acquisitions.

Our focus is on making profitable investments while operating within cash flow, maintaining sufficient liquidity, cost reductions and fulfilling our contractual, legal and financial obligations. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans.

Results of Operations

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

Revenues. Total revenues decreased $45.8 million, or 7.9%, to $534.9 million in 2019 as compared to $580.7 million in 2018. Oil revenues decreased $39.0 million, or 8.9%, NGLs revenues decreased $14.8 million, or 39.7%, natural gas revenues increased $6.7 million, or 6.7%, and other revenues increased $1.2 million. The oil revenue decrease was attributable to an 8.7% per barrel decrease in the average realized sales price to $59.89 per barrel in 2019 from $65.62 per barrel in 2018 and a 0.2% decrease in sales volumes. The NGLs revenue decrease was attributable to a 38.0% decrease in the average realized sales price to $17.60 per barrel in 2019 from $28.40 per barrel in 2018 and a decrease of 2.8% in sales volumes. The increase in natural gas revenue was attributable to a 29.1% increase in sales volumes, partially offset by a 17.4% decrease in the average realized natural gas sales price to $2.57 per Mcf in 2019 from $3.11 per Mcf in 2018. Overall, prices decreased 17.5 % on a per Boe basis and production increased 11.3% on a per Boe per day basis. The largest production increases for 2019 compared to 2018 were from our newly acquired interest in the Mobile Bay Properties and at Mahogany. Partially offsetting were production decreases primarily due to natural production declines and production deferrals. Production for 2019 was also negatively impacted by maintenance, well issues and pipeline outages that collectively resulted in deferred production of 2.1 MMBoe, compared to 1.6 MMBoe in 2018.

Revenues from oil and liquids as a percent of our total revenues were 78.9% for 2019 compared to 82.0% for 2018. NGLs average realized sales price as a percent of crude oil average realized price decreased to 29.4% for 2019 compared to 43.3% for 2018.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workovers, and facilities maintenance expenses, increased $31.0 million, or 20.2%, to $184.3 million in 2019 compared to $153.3 million in 2018. The acquisition of the Mobile Bay Properties accounted for approximately half of the lease operating expense increase. On a per Boe basis, lease operating expenses increased to $12.43 per Boe during 2019 compared to $11.50 per Boe during 2018. On a component basis, base lease operating expenses increased $17.6 million, insurance premiums increased $0.2 million, workover expenses increased $7.3 million and facilities maintenance expenses increased $5.9 million. Base lease operating expenses increased primarily due to the addition of the Mobile Bay Properties, acquired in August 2019, and the Heidelberg field, acquired in April 2018. The increase in workover expenses is primarily attributable to additional projects at our Mahogany and Gladden fields to increase production. The increase in facilities maintenance expenses involved several projects with no one project representing the majority of the increase.

Production taxes. Production taxes were $2.5 million, an increase of $0.7 million due to the acquisition of the Mobile Bay Properties. Most of our production is from federal waters where no production taxes are imposed. The Mobile Bay Properties and our Fairway field, both of which are in state waters, are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased to $26.0 million, or 15.9%, in 2019 compared to $22.4 million in 2018 primarily related to the Mobile Bay Properties and the Heidelberg field.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $10.01 per Boe in 2019 from $11.24 per Boe in 2018. On a nominal basis, DD&A decreased to $148.5 million (0.9%) in 2019 from $149.9 million in 2018. DD&A on a nominal basis decreased primarily due to a lower rate per Boe due to the year-over-year increase in proved reserves. Other factors affecting the DD&A rate are capital expenditures and changes in future development costs on remaining reserves.

General and administrative expenses ("G&A"). For 2019, G&A expenses were $55.1 million compared to $60.1 million in 2018. We experienced reductions in expense primarily from higher overhead charged out (credits) on certain drilling projects; lower medical claims; lower incentive compensation expenses; and lower surety bond expenses, partially offset by increased contractor and professional services expenses. G&A on a per BOE basis was $3.72 Boe for 2019 compared to $4.51 Boe for 2018.

Derivative loss (gain). For 2019, a $59.9 million derivative loss was recorded for crude oil and natural gas derivative contracts. We entered into derivative contracts for crude oil during the fourth quarter of 2019 for both certain crude oil and natural gas derivative contracts. For 2018, a $53.8 million derivative gain was recorded for crude oil and natural gas derivative contracts. The gain in 2018 and loss in 2019 are primary due to crude oil prices falling in the latter months of 2018 and subsequently increasing in 2019 relative to the year-end 2018 crude oil prices, which impacted future prices used to value the derivative contracts in 2018 and 2019, respectively. See *Financial Statements and Supplementary Data – Note 9 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Interest expense, net. Interest expense, net, was $59.6 million in 2019, increasing 22.5% from $48.6 million in 2018. The increase was primarily attributable to the issuance of the Senior Second Lien Notes, execution of the Credit Agreement and extinguishment of the Company's prior debt instruments (the "Refinancing Transaction"). Prior to the Refinancing Transaction, $25.6 million of interest costs on certain debt instruments for the period of January 1, 2018 to October 18, 2018 was recorded against the carrying value adjustments established under Accounting Standard Codification Topic 470-60, *Troubled Debt Restructuring* ("ASC 470-60"). After the Refinancing Transaction, all of our interest cost is reported as interest expense. In addition, interest expense increased related to increased borrowings under the Credit Agreement in 2019 compared to 2018. Partially offsetting the increase in interest expenses was an increase in interest income to $7.7 million in 2019 compared to $2.4 million in 2018, primarily due to interest income related to the income tax refunds, Apache and RIK matters, each matter containing an element of interest income. *See Financial Statements and Supplementary Data - Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information on our debt.

Gain on exchange of debt. During 2018, the Refinancing Transaction resulted in a gain of $47.1 million for 2018. *See Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for additional information.

Other (income) expense, net. During 2019, other expense, net, was $0.2 million, compared to $3.9 million of other income, net, for 2018. For 2019, the amount consists primarily of federal royalty obligation reductions claimed in the current year related to capital deductions from prior periods, and partially offset by expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program. For 2018, the amount consists primarily of credits related to the de-recognition of certain liabilities that had exceeded the statute of limitations, partially offset by expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program.

Income tax benefit (expense). Our income tax benefit for 2019 was $75.2 million and our income tax expense for 2018 was $0.5 million. For 2019, our income tax benefit was primarily due to reversals of previously recorded valuation allowances and for the reversal of a liability related to an uncertain tax position that was effectively settled with the Internal Revenue Service ("IRS") during the year. For 2018, immaterial deferred tax expense was recorded due to dollar-for-dollar offsets by our valuation allowance. Our annual effective tax rate for 2019 and 2018 was not meaningful and differs from the federal statutory rates of 21% primarily due to the valuation allowance adjustments recorded for our deferred tax assets in both periods. During 2019, we recorded a net decrease to the valuation allowance of $63.3 million related to federal and state deferred tax assets and a reversal of an uncertain tax position resulting in a non-cash tax benefit of $11.5 million. During 2018, we recorded a decrease to the valuation allowance of $53.8 million related to federal and state deferred tax assets. A corresponding change for substantially an equivalent amount occurred in our deferred tax assets for 2018. Deferred tax assets are recorded related to net operating losses ("NOL") and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or NOLs are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

For 2020, we do not expect to make any significant income tax payments. See *Financial Statements and Supplementary Data – Note 13 – Income Taxes* under Part II, Item 8 in this Form 10-K for additional information.

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

For year-to-year comparisons between 2018 and 2017 that are not included in this Annual Report on Form 10-K, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings, make related interest payments and satisfy our AROs. We have funded such activities in the past with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings.

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

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

- recognizing ceiling test write-downs of the carrying value of our oil and gas properties;
- reductions in our proved reserves and the estimated value thereof;
- additional supplemental bonding and potential collateral requirements;
- reductions in our borrowing base under the Credit Agreement; and
- our ability to fund capital expenditures needed to replace produced reserves, which must be replaced on a long-term basis to provide cash to fund liquidity needs described above.

Joint Venture Drilling Program. To provide additional financial flexibility, we created the Joint Venture Drilling Program with private investors during 2018 and completed nine drilling projects by the end of 2019. The Joint Venture Drilling Program enables W&T to receive returns on its investment on a promoted basis and enables private investors to participate in certain drilling projects. It also allows more projects to be taken on with our capital expenditures budget and reduces our risk via diversification. In the Joint Venture Drilling Program, five wells came on line during 2019 and four came on line during 2018. For the first half of 2020, two wells are scheduled to be drilled and, if successful, are expected to start producing in late 2020 or early 2021. See *Financial Statements and Supplementary Data – Note 4 – Joint Venture Drilling Program* under Part II, Item 8 in this Form 10-K for additional information on the Joint Venture Drilling Program.

Refinancing Transaction. In October 2018, we entered into a series of transactions to refinance substantially all of our outstanding indebtedness. At that time, we issued $625.0 million of the Senior Second Lien Notes, which were issued at par with an interest rate of 9.75% per annum that matures on November 1, 2023. Concurrently, we renewed our credit facility by entering into the Credit Agreement, which matures on October 18, 2022 and increased the borrowing base from $150.0 million to $250.0 million and it remained at this level as of December 31, 2019. Funds from the Senior Second Lien Notes, cash on hand and borrowings under the Credit Agreement were used to repurchase and retire, repay or redeem all of our previously outstanding secured senior notes and secured term loans. The Refinancing Transaction reduced our debt levels, extended the maturities for our fixed rate debt and provides extended liquidity under the Credit Agreement through October 2022. See *Financial Statements and Supplementary Data – Note 2 – Long-Term Debt* under Part II, Item 8 in this Form 10-K for a full description of the transaction and the new debt instruments.

Credit Agreement. As of December 31, 2019, we had $105.0 million borrowings outstanding under the Credit Agreement and $5.8 million of letters of credit issued under the Credit Agreement. During 2019, borrowings under the Credit Agreement ranged from zero to $150.0 million. Availability under our Credit Agreement as of December 31, 2019 was $139.2 million. Availability under our Credit Agreement is subject to a semi-annual redetermination of our borrowing base to occur around May 15th and November 14th each calendar year, and certain additional redeterminations that may be requested at the discretion of either the lenders or the Company. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our Credit Agreement. The borrowing base remained at $250.0 million as of December 31, 2019 following the latest redetermination. The Credit Agreement is secured and is collateralized by substantially all of our oil and natural gas properties. We currently have six lenders within the revolving bank credit facility, with commitments ranging from $25.0 million to $62.5 million for the current borrowing base. While we have not experienced, nor do we anticipate, any difficulties in obtaining funding from any of these lenders at this time, any lack of or delay in funding by members of our banking group could negatively impact our liquidity position. The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement and the other debt instruments as of December 31, 2019.

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

BOEM Matters. As of the filing date of this Form 10-K, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to financial assurance obligations. We and other offshore Gulf of Mexico producers may, in the ordinary course of business, receive demands in the future for financial assurances from the BOEM. For more information on the BOEM and financial assurance obligations to that agency, see *Business–Regulation–Decommissioning and Financial Assurance Requirements* under Part I, Item 1 of this Form 10-K.

Surety Bond Collateral. Some of the sureties that provide us surety bonds used for supplemental financial assurance purposes have requested and received collateral from us, and may request additional collateral from us in the future, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety's discretion. We did not receive any such demands in 2019 or 2018. The issuance of any additional surety bonds or other security to satisfy future BOEM orders, collateral requests from surety bond providers, and collateral requests from other third-parties may require the posting of cash collateral, which may be significant, and may require the creation of escrow accounts.

Cash Flows. Net cash provided by operating activities for 2019 was $232.2 million, decreasing $89.5 million, or 27.8%, from 2018. The change between periods is primarily due to lower realized prices for crude oil, NGLs and natural gas, changes in cash advances and working capital changes, partially offset by increased volumes, lower spending for ARO activities, derivatives and income tax refunds. Our combined average realized sales price per Boe decreased 17.5% in 2019, which caused total revenues to decrease $74.3 million, partially offset by increases of 11.3% in overall production volumes which caused revenues to increase by $27.2 million.

Other items affecting operating cash flows for 2019 were: ARO settlements of $11.4 million, which decreased from $28.6 million in 2018; cash advances from joint venture partners decreased $15.3 million during 2019 compared to an increase of $16.6 million during 2018; derivative receipts, net, were $13.9 million in 2019 compared to derivative cash payments, net, of $28.2 million in 2018; and income tax refunds were $51.8 million in 2019 compared to income tax refunds of $11.1 million in 2018.

Net cash used in investing activities during 2019 and 2018 was $313.8 million and $66.4 million, respectively, which represents our acquisitions and investments in oil and gas properties and equipment. Investments in oil and natural gas properties 2019 were $125.7 million, which was an increase of $19.5 million from 2018. The majority of our capital expenditures for 2019 related to investments on the conventional shelf in the Gulf of Mexico and, to a lesser extent, in the deepwater of the Gulf of Mexico. The acquisition of property interest of $188.0 million was primarily related to the acquisition of the Mobile Bay Properties and, to a lesser extent, the acquisition of the Magnolia Field. During 2018, the acquisition of property interests of $16.8 million was for the acquisition of the Heidelberg field. The sale of our overriding royalty interests in the Permian Basin fields resulted in net proceeds of $56.6 million in 2018 and there were no asset sales of significance in 2019.

Net cash provided by financing activities for 2019 was $80.7 million and net cash used by financing activities for 2018 was $321.1 million. The net cash provided by financing activities in 2019 was from borrowings under the Credit Agreement to fund the acquisition of the Mobile Bay Properties, of which a portion was paid down by December 31, 2019. The net cash used for 2018 was primarily related to the Refinancing Transaction which included issuance of the Senior Second Lien Notes and extinguishment of all of the prior debt instruments. In addition, cash used during 2018 included interest payments on certain debt, which are reported as financing activities under ASC 470-60.

Derivative financial instruments. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. During 2019 and 2018, we entered into commodity contracts for crude oil and natural gas which related to a portion of our expected production for the time frames covered by the contracts. As of December 31, 2019, we had outstanding open derivatives for crude oil and natural gas. See *Financial Statements and Supplementary Data - Note 10 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K for additional information.

Insurance Coverage. We currently carry multiple layers of insurance coverage in our Energy Package (defined as certain insurance policies relating to our oil and gas properties which include named windstorm coverage) covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy is effective for one year beginning June 1, 2019 and limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. With respect to coverage for named windstorms, we have a $162.5 million aggregate limit covering all of our higher valued properties, and $150.0 million for all other properties subject to a retention of $30.0 million. Included within the $162.5 million aggregate limit is TLO coverage on our Mahogany platform, which has no retention. The operational and named windstorm coverages are effective for one year beginning June 1, 2019. Coverage for pollution causing a negative environmental impact is provided under the well control and other sections within the policy.

Our general and excess liability policies are effective for one year beginning May 1, 2019 and provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE and we have insurance coverage of such amount. We do not carry business interruption insurance.

The premiums for the above policies including brokerage fees were $10.9 million for the May/June 2019 policy renewals compared to $11.8 million for the expiring policies. The change in our premiums effective with the May/June 2019 renewal was primarily attributable to negotiations.

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

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Exploration (1)	$ 17,121	$ 49,890	$ 57,088
Development (1)	107,662	47,224	71,054
Acquisition of interest – Mobile Bay Properties (2)	170,689	—	—
Acquisition of interest – Magnolia Field (3)	15,950	—	—
Acquisition of interest – Heidelberg Field (4)	—	16,782	—
Reimbursement from Monza for 2017 expenditures	—	(14,075)	—
Seismic and other	14,412	7,702	1,906
Acquisitions and investments in oil and gas property/equipment – accrual basis	$ 325,834	$ 107,523	$ 130,048

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

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

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Conventional shelf	$ 39,093	$ 69,354	$ 121,922
Deepwater	85,690	27,760	6,220
Exploration and development capital expenditures – accrual basis	$ 124,783	$ 97,114	$ 128,142

The capital expenditures reported in the above two tables are included within *Oil and natural gas properties and other, net* on the Consolidated Balance Sheets. The capital expenditures reported within the Investing section of the Consolidated Statements of Cash Flows include adjustments for payments related to capital expenditures.

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

	Completed		
	2019	2018	2017
Offshore – gross wells drilled:			
Conventional shelf	3	3	4
Deepwater	3	3	—
Wells operated by W&T	5	5	4

We had a 100% success rate in 2019 and 2018, and an 80% success rate in 2017. During 2019, the following wells were completed: the Virgo A-13 exploration well; the South Timbalier 320 A-3 development well; the Gladden SS002 exploration well; the Ship Shoal 028 041 development well; the East Cameron 321 B-8 ST1 development well; and the Mahogany A-6 ST1 development well. All of these wells are in the Joint Venture Drilling Program except for the Mahogany A-6 ST1 well.

During the first two months of 2020, there was one well being drilled, which is in the Joint Venture Drilling Program.

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

See *Properties –Development of Proved Undeveloped Reserves* under Part I, Item 2 of this Form 10-K for a discussion on activity related to proved undeveloped reserves.

Lease Acquisitions. Over the last three years, we have acquired 35 leases for approximately $5.8 million from the BOEM in the Federal Offshore Lease Sales. Per year, we acquired 17 leases ($3.8 million), 17 leases ($1.9 million) and one lease ($0.1 million) in the years 2019, 2018 and 2017, respectively.

Divestitures. From time to time, we sell various oil and gas properties for a variety of reasons including, change of focus, perception of value and to reduce debt, among other reasons. As previously discussed, in 2018 we sold our overriding interests in the Yellow Rose field for $56.6 million after adjustments. In 2019 and 2017, there were no property sales of significance. See *Financial Statements and Supplementary Data – Note 5 –Acquisitions and Divestitures* under Part II, Item 8 in this Form 10-K for additional information on this divestiture.

Liquidity for 2020. We believe that we will have adequate liquidity from cash flow from operations to fund our capital expenditure plans for 2020, fund our ARO spending for 2020 and fulfill our various other obligations. Availability under our Credit Agreement as of December 31, 2019 was $139.2 million. Our preliminary capital expenditure budget for 2020 has been established in the range of $50.0 million to $100.0 million, which includes our share of the Joint Venture Drilling Program, and excludes acquisitions. In our view of the outlook for 2020, we believe this level of capital expenditure will enhance our liquidity capacity throughout 2020 and beyond. If our liquidity becomes stressed from significant reductions in realized prices, we have flexibility in our capital expenditure budget to reduce investments. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments.

Income taxes. As of December 31, 2019, we have current income taxes receivable of $1.9 million. During 2019, we received refunds of $51.8 million and interest income of $4.5 million primarily related to our NOL claims for the years 2012, 2013 and 2014 that were carried back to prior years. The claims were made pursuant to Internal Revenue Code ("IRC") rules for specified liability losses, which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. Under the Tax Cuts and Jobs Act (“TJCA”), effective in 2017, NOLs including those related to specified liability losses can no longer be carried back for tax years beginning after 2017. An additional carryback claim for specified liability losses generated in 2017 has been filed with an estimated receivable of $2.0 million. For 2020, we do not expect to make any significant income tax payments.

Dividends. During 2019, 2018 and 2017, we did not pay any dividends and a suspension of dividends remains in effect.

Asset retirement obligations. Annually we review and revise our ARO estimates. Our ARO at December 31, 2019 and 2018 were $355.6 million and $310.1 million, respectively, recorded using discounted values. Our estimate of ARO spending in 2020 is $15.0 million to $25.0 million. During 2019 and 2018, we revised our estimates of costs anticipated to be charged by service providers for plugging and abandonment projects and revised estimated to actual spending as invoices were processed and projects completed. As these estimates are for work to be performed in the future, and in many cases, several years in the future, actual expenditures could be substantially different than our estimates. Additionally, we revise our estimates to account for the cost to comply with any new or revised regulations, including increases in work scope and cost changes from interpretation of work scope. See Risk Factors – *Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant because our operations are concentrated in the Gulf of Mexico* under Part I, Item 1A and *Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations* under Part II, Item 8 in this Form 10-K for additional information regarding our ARO.

Contractual obligations. At December 31, 2019, we did not have any capital leases. The following table summarizes our significant contractual obligations by maturity as of December 31, 2019 (in millions):

	Payments Due by Period as of December 31, 2019				
	Total	Less than One Year	One to Three Years	Three to Five Years	More Than Five Years
Long-term debt – principal	$ 730.0	$ —	$ 105.0	$ 625.0	$ —
Long-term debt – interest (1)	258.8	66.3	131.6	60.9	—
Operating leases	14.8	2.8	0.6	1.3	10.1
Asset retirement obligations (2)	355.6	22.0	45.5	60.4	227.7
Other liabilities and commitments (3)	86.0	8.3	13.0	11.4	53.3
Total	$ 1,445.2	$ 99.4	$ 295.7	$ 759.0	$ 291.1

(1) Interest payments were calculated through the stated maturity date of the related debt: (a) Interest payments for the Credit Agreement were calculated using the interest rate applied to our outstanding balance as of December 31, 2019 and assumes no change in this interest rate in future periods. In addition, a commitment fee of 0.375% was applied on the available balance as of December 31, 2019 and fees related to letters of credit were estimated at the rate incurred on December 31, 2019; (b) Interest payments on the Senior Second Lien Notes were calculated per the terms of the notes.

(2) ARO in the above table is presented on a discounted basis, consistent with the amounts reported on the Consolidated Balance Sheet as of December 31, 2019 and are estimates of future payments. Actual payments and the timing of the payments may be significantly different than our estimates. All other amounts in the above table are presented on an undiscounted basis.

(3) Other liabilities and commitments primarily consist of estimated fees for surety bonds related to obligations under certain purchase and sale agreements and for supplemental bonding for plugging and abandonment. As of December 31, 2019, we had approximately $382.6 million of bonds outstanding, with the majority related to plugging and abandonment obligations. The amounts are based on current market rates and conditions for these types of bonds and are subject to change. Excluded are potential increases in surety bond requirements which cannot be determined. Included are estimates of minimum quantities obligations for certain pipeline contracts which were assumed in conjunction with the purchase of an interest in the Heidelberg field. The above table excludes our obligations under joint interest arrangements related to commitments that have not yet been incurred. In these instances, we are obligated to pay, according to our interest ownership, a portion of exploration and development costs, operating costs and potentially could be offset by our interest in future revenue from these non-operated properties. These joint interest obligations for future commitments cannot be determined due to the variability of factors involved. See *Financial Statements and Supplementary Data – Note 16 – Commitments* under Part II, Item 8 in this 10-K for additional information.

Inflation and Seasonality

Inflation. For 2019, our realized prices for crude oil decreased 8.7%, NGLs decreased 38.0% and natural gas decreased 17.4% from 2018. These are discussed in the *Overview* section above. Historically, our costs for goods and services have moved directionally with the price of crude oil, NGLs and natural gas, as these commodities affect the demand for these goods and services. Operating costs directly related to production (lease operating expenses, production taxes and gathering and transportation) measured on a $/Boe basis increased by 7.7% in 2019 compared to 2018 and increased by 17.0% in 2018 compared to 2017. These operating costs related to production are substantially impacted by factors other than national general rates of inflation or deflation, such as workovers, facility repairs, production handling fees for certain fields (recorded as credits to expense), production levels, hurricanes, changes in regulations, types of commodities produced and the level of oil and gas activity in the Gulf of Mexico.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with GAAP in the United States. The preparation of our financial statements requires us to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our estimates on historical experience and other sources that we believe to be reasonable at the time. Changes in the facts and circumstances or the discovery of new information may result in revised estimates and actual results may vary from our estimates. Our significant accounting policies are detailed in *Financial Statements and Supplementary Data – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

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

We record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. If crude oil and natural gas prices decrease, we may need to increase this liability. Also, disputes may arise as to volume measurements and allocation of production components between parties. These disputes could cause us to increase our liability for such potential exposure. We do not record receivables for those properties in which the Company has taken less than its ownership share of production which could cause us to delay recognition of amounts due us.

Full-cost accounting. We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Capitalization of geological and geophysical costs, certain employee costs and G&A expenses related to these activities is permitted. We amortize our investment in oil and natural gas properties, capitalized ARO and future development costs (including ARO of wells to be drilled) through DD&A, using the units-of-production method. The units-of-production method uses reserve information in its calculations. The cost of unproved properties related to acquisitions are excluded from the amortization base until it is determined that proved reserves exist or until such time that impairment has occurred. We capitalize interest on unproved properties that are excluded from the amortization base. The costs of drilling non-commercial exploratory wells are included in the amortization base immediately upon determination that such wells are non-commercial. Under the full-cost method, sales of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized unless an adjustment would significantly alter the relationship between capitalized costs and the value of proved reserves.

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

DD&A can be affected by several factors other than production. The rate computation includes estimates of reserves which requires significant judgment and is subject to change at each assessment. The determination of when proved reserves exist for our unproved properties requires judgment, which can affect our DD&A rate. Also, estimates of our ARO and estimates of future development costs require significant judgment. Actual results may be significantly different from such estimates, which would affect the timing of when these expenses would be recognized as DD&A. See *Oil and natural gas reserve quantities* and *Asset retirement obligations* below for more information.

Impairment of oil and natural gas properties. Under the full-cost method of accounting, we are required to perform a "ceiling test" calculation quarterly, which determines a limit on the book value of our oil and natural gas properties. Any write downs occurring as a result of the ceiling test impairment are not recoverable or reversible in future periods. We did not have any ceiling test impairments in 2019, 2018 or 2017, but did have ceiling test impairments in 2016 and 2015. Ceiling test impairments in future periods are highly dependent on commodity prices, and also are impacted by other factors and events. For the effect of lower commodity prices on revenues and earnings, see *Quantitative and Qualitative Disclosures on Market Risks* under Part II, Item 7A in this Form 10-K for additional information.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of DD&A and impairment assessment of our oil and natural gas properties. We make changes to DD&A rates and impairment calculations in the same period that changes to our reserve estimates are made. Our proved reserve information as of December 31, 2019 included in this Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as the future prices of crude oil and natural gas; and
- the judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered.

Asset retirement obligations. We have significant obligations to plug and abandon all well bores, remove our platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site cleanup. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because the removal obligations may be many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. Pursuant to GAAP, we are required to record a separate liability for the discounted present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet.

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

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

Income taxes. GAAP requires the use of the liability method of computing deferred income taxes, whereby deferred income taxes are recognized for the future tax consequences of the differences between the tax basis of assets and liabilities and the carrying amount in our financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Because our tax returns are filed after the financial statements are prepared, estimates are required in recording tax assets and liabilities. We record adjustments to reflect actual taxes paid in the period we complete our tax returns. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense. The final settlement of these tax positions may occur several years after the tax return is filed and may result in significant adjustments depending on the outcome of these settlements.

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

Troubled Debt Restructuring. We accounted for certain debt issued in 2016 as a troubled debt restructuring pursuant to the guidance under ASC 470-60 which requires the carrying value of the debt to be measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for certain debt in the Consolidated Statements of Operations from September 7, 2016 to October 18, 2018. Thus, our reported interest expense was significantly less than the contractual interest payments during 2018 and 2017.

Leases. We account for leases under the under Accounting Standards Update 2016-02, Leases (*Topic 842*) ("ASU 2016-02") which was effective for us on January 1, 2019. Under the revised guidance, we are required to determine if an arrangement meets the definition of a lease and, if so, whether the lease is a finance or operating lease which impacts the recognition, measurement and presentation of expenses. Under ASU 2016-02, we recognize a right-of-use ("ROU") asset and lease liability for all leases with a term greater than 12 months. Leases acquired to explore for or extract oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained, are not within the scope of this standard's update. The calculation of ROU assets and liabilities for leases includes a discount factor estimating the interest rate on incremental debt, which is imprecise as we issue debt indentures infrequently. Also, we are required to estimate the term of lease, which can be different from the contractual term, and may lead to adjustments if events are different from our estimates.

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

We are exposed to market risks arising from fluctuating prices of crude oil, NGLs, natural gas and interest rates as discussed below. We have utilized derivative contracts from time to time to reduce the risk of fluctuations in commodity prices and expect to use these instruments in the future. We entered into derivative contracts for crude oil and natural gas during 2019 and had open derivative contracts as of December 31, 2019. We do not designate our commodity derivative contracts as hedging instruments. While derivative contracts are intended to reduce the effects of volatile oil prices, they may also limit income from favorable price movements. For additional details about our derivative contracts, refer to *Financial Statements and Supplementary Data – Note 10 – Derivative Financial Instruments* under Part II, Item 8 in this Form 10-K.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices for crude oil, NGLs and natural gas, which fluctuate widely. Crude oil, NGLs and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. For example, assuming a 10% decline in our average realized oil, NGLs and natural gas sales prices in 2019 and assuming no other items had changed, our loss before income tax would have increased by approximately $53.0 million in 2019. If costs and expenses of operating our properties had increased by 10% in 2019, our loss before income tax would have increased by approximately $21.0 million in 2019. These amounts would be representative of the effect on operating cash flows under these price and cost change assumptions.

Interest rate risk. As of December 31, 2019, we had $105.0 outstanding on our Credit Agreement. The Credit Agreement has a variable interest rate which is primarily impacted by the rates for the London Interbank Offered Rate and the current margin ranges from 2.50% to 3.50% depending on the amount outstanding. In 2019, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have increased $1.5 million during 2019. We did not have any derivative contracts related to interest rates as of December 31, 2019.

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even effective internal control over financial reporting can only provide reasonable assurance of achieving their control objectives.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework).

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2019 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The effectiveness of our internal control over financial reporting as of December 31, 2019 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of W&T Offshore, Inc. and Subsidiaries

Opinion on Internal Control over Financial Reporting

We have audited W&T Offshore, Inc. and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, W&T Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2019 and 2018, and the related consolidated statements of operations, changes in shareholders' deficit and cash flows for each of the three years in the period ended December 31, 2019 and related notes and our report dated March 5, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Houston, Texas
March 5, 2020

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of W&T Offshore, Inc. and Subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and subsidiaries (the Company) as of December 31, 2019 and 2018, and the related consolidated statements of operations, changes in shareholders' deficit and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 5, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

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

Houston, Texas
March 5, 2020

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

	December 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 32,433	$ 33,293
Receivables:		
Oil and natural gas sales	57,367	47,804
Joint interest, net	19,400	14,634
Income taxes	1,861	54,076
Total receivables	78,628	116,514
Prepaid expenses and other assets (Note 1)	30,691	76,406
Total current assets	141,752	226,213
Oil and natural gas properties and other, net – at cost: (Note 1)	748,798	515,421
Restricted deposits for asset retirement obligations	15,806	15,685
Deferred income taxes	63,916	—
Other assets (Note 1)	33,447	91,547
Total assets	$ 1,003,719	$ 848,866
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$ 102,344	$ 82,067
Undistributed oil and natural gas proceeds	29,450	28,995
Advances from joint interest partners	5,279	20,627
Asset retirement obligations	21,991	24,994
Accrued liabilities (Note 1)	30,896	29,611
Total current liabilities	189,960	186,294
Long-term debt: (Note 2)		
Principal	730,000	646,000
Carrying value adjustments	(10,467)	(12,465)
Long-term debt – carrying value	719,533	633,535
Asset retirement obligations, less current portion	333,603	285,143
Other liabilities (Note 1)	9,988	68,690
Commitments and contingencies (Note 18)	—	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000 shares authorized; 0 issued at December 31, 2019 and December 31, 2018	—	—
Common stock, $0.00001 par value; 200,000 shares authorized; 144,538 issued and 141,669 outstanding at December 31, 2019 and 143,513 issued and 140,644 outstanding at December 31, 2018	1	1
Additional paid-in capital	547,050	545,705
Retained deficit	(772,249)	(846,335)
Treasury stock, at cost; 2,869 shares at December 31, 2019 and December 31, 2018	(24,167)	(24,167)
Total shareholders' deficit	(249,365)	(324,796)
Total liabilities and shareholders' deficit	$ 1,003,719	$ 848,866

See accompanying notes.

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Revenues:			
Oil	$ 399,790	$ 438,798	$ 340,010
NGLs	22,373	37,127	32,257
Natural gas	106,347	99,629	108,923
Other	6,386	5,152	5,906
Total revenues	534,896	580,706	487,096
Operating costs and expenses:			
Lease operating expenses	184,281	153,262	143,738
Production taxes	2,524	1,832	1,740
Gathering and transportation	25,950	22,382	20,441
Depreciation, depletion and amortization	129,038	131,423	138,510
Asset retirement obligations accretion	19,460	18,431	17,172
General and administrative expenses	55,107	60,147	59,744
Derivative loss (gain)	59,887	(53,798)	(4,199)
Total costs and expenses	476,247	333,679	377,146
Operating income	58,649	247,027	109,950
Interest expense, net	59,569	48,645	45,521
Gain on debt transactions	—	47,109	7,811
Other expense (income), net	188	(3,871)	5,127
(Loss) income before income tax (benefit) expense	(1,108)	249,362	67,113
Income tax (benefit) expense	(75,194)	535	(12,569)
Net income	$ 74,086	$ 248,827	$ 79,682
Basic and diluted earnings per common share	$ 0.52	$ 1.72	$ 0.56

See accompanying notes.

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

	Common Stock Outstanding		Additional Paid-In Capital	Retained Deficit	Treasury Stock		Total Shareholders' Deficit
	Shares	Value			Shares	Value	
Balances at December 31, 2016	137,674	$ 1	$ 539,973	$(1,174,844)	2,869	$ (24,167)	$ (659,037)
Share-based compensation	—	—	7,191	—	—	—	7,191
Stock issued	1,417	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(1,344)	—	—	—	(1,344)
Net income	—	—	—	79,682	—	—	79,682
Balances at December 31, 2017	139,091	1	545,820	(1,095,162)	2,869	(24,167)	(573,508)
Share-based compensation	—	—	3,540	—	—	—	3,540
Stock issued	1,553	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(3,655)	—	—	—	(3,655)
Net income	—	—	—	248,827	—	—	248,827
Balances at December 31, 2018	140,644	1	545,705	(846,335)	2,869	(24,167)	(324,796)
Share-based compensation	—	—	3,690	—	—	—	3,690
Stock issued	1,025	—	—	—	—	—	—
RSUs surrendered for payroll taxes	—	—	(2,345)	—	—	—	(2,345)
Net income	—	—	—	74,086	—	—	74,086
Balances at December 31, 2019	141,669	$ 1	$ 547,050	$ (772,249)	2,869	$ (24,167)	$ (249,365)

See accompanying notes.

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Operating activities:			
Net income	$ 74,086	$ 248,827	$ 79,682
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	148,498	149,854	155,682
Gain on debt transactions	—	(47,109)	(7,811)
Amortization of debt items and other items	5,514	2,850	1,715
Share-based compensation	3,690	3,540	7,191
Derivative loss (gain)	59,887	(53,798)	(4,199)
Derivatives cash receipts (payments), net	13,941	(28,164)	4,199
Deferred income taxes	(64,102)	500	217
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(9,563)	(2,361)	(2,370)
Joint interest receivables	(4,766)	5,120	2,131
Insurance reimbursements	—	—	31,740
Income taxes	52,214	11,028	(1,063)
Prepaid expenses and other assets	(9,346)	3,383	3,238
Escrow deposit - Apache lawsuit	—	—	(49,500)
Asset retirement obligation settlements	(11,443)	(28,617)	(72,409)
Cash advances from JV partners	(15,347)	16,629	(437)
Accounts payable, accrued liabilities and other	(11,036)	40,081	11,402
Net cash provided by operating activities	232,227	321,763	159,408
Investing activities:			
Investment in oil and natural gas properties and equipment	(125,706)	(106,191)	(106,174)
Acquisition of property interests	(188,019)	(16,782)	—
Proceeds from sales of assets, net	—	56,588	—
Purchases of furniture, fixtures and other	(89)	—	(933)
Net cash used in investing activities	(313,814)	(66,385)	(107,107)
Financing activities:			
Borrowings on credit facility	150,000	61,000	—
Repayments on credit facility	(66,000)	(40,000)	—
Issuance of Senior Second Lien Notes	—	625,000	—
Extinguishment of debt – principal	—	(903,194)	—
Extinguishment of debt – premiums	—	(21,850)	—
Payment of interest on 1.5 Lien Term Loan	—	(6,623)	(8,227)
Payment of interest on 2nd Lien PIK Toggle Notes	—	(9,725)	(7,335)
Payment of interest on 3rd Lien PIK Toggle Notes	—	(4,672)	(6,201)
Debt transactions costs	(939)	(17,457)	(421)
Other	(2,334)	(3,622)	(1,295)
Net cash provided by (used in) financing activities	80,727	(321,143)	(23,479)
(Decrease) increase in cash and cash equivalents	(860)	(65,765)	28,822
Cash and cash equivalents, beginning of period	33,293	99,058	70,236
Cash and cash equivalents, end of period	$ 32,433	$ 33,293	$ 99,058

See accompanying notes

1. Significant Accounting Policies

Operations

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

Basis of Presentation

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

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

Realized Prices

The price we receive for our crude oil, natural gas liquids ("NGLs") and natural gas production directly affects our revenues, profitability, cash flows, liquidity, access to capital, proved reserves and future rate of growth. The average realized prices of these commodities decreased in 2019 compared to the average realized prices in 2018.

Accounting Standard Updates Effective January 1, 2019

In February 2016, Accounting Standards Update 2016-02, Leases (*Topic 842*) ("ASU 2016-02") was issued requiring an entity to recognize a right-of-use ("ROU") asset and lease liability for all leases. The classification of leases as either a finance or operating lease determines the recognition, measurement and presentation of expenses. ASU 2016-02 also requires certain quantitative and qualitative disclosures about leasing arrangements. Leases acquired to explore for or extract oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained, are not within the scope of this standard's update. ASU 2016-02 was effective for us in the first quarter of 2019 and we adopted the new standard using a modified retrospective approach, with the date of initial application on January 1, 2019. Consequently, upon transition, we recognized an ROU asset and a lease liability with no retained earnings impact. See Note 7 for additional information.

Cash Equivalents

We consider all highly liquid investments purchased with original or remaining maturities of three months or less at the date of purchase to be cash equivalents.

Revenue Recognition

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

We record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which we have taken less than our ownership share of production. At December 31, 2019 and 2018, $3.6 million and $4.1 million, respectively, were included in current liabilities related to natural gas imbalances.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies and large commodity trading companies. The majority of our production is sold utilizing month-to-month contracts that are based on bid prices. We attempt to minimize our credit risk exposure to purchasers of our oil and natural gas, joint interest owners, derivative counterparties and other third-party entities through formal credit policies, monitoring procedures, and letters of credit or guarantees when considered necessary.

The following table identifies customers from whom we derived 10% or more of our receipts from sales of crude oil, NGLs and natural gas:

	Year Ended December 31,		
	2019	2018	2017
Customer			
Shell Trading (US) Co./ Shell Energy N.A.	11%	30%	46%
BP Products North America	40%	20%	**
Vitol Inc.	12%	14%	15%

** Less than 10%

We believe that the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and natural gas production as replacement customers could be obtained in a relatively short period of time on terms, conditions and pricing substantially similar to those currently existing.

Accounts Receivables and Allowance for Bad Debts

Our accounts receivables are recorded at their historical cost, less an allowance for doubtful accounts. The carrying value approximates fair value because of the short-term nature of such accounts. In addition to receivables from sales of our production to our customers, we also have receivables from joint interest owners on properties we operate. In certain arrangements, we have the ability to withhold future revenue disbursements to recover amounts due us from the joint interest partners. We use the specific identification method of determining if an allowance for doubtful accounts is needed and the amounts recorded relate to certain joint interest owners. The following table describes the balance and changes to the allowance for doubtful accounts (in thousands):

	2019	2018	2017
Allowance for doubtful accounts, beginning of period	$ 9,692	$ 9,114	$ 7,602
Additional provisions for the year	206	1,233	1,512
Uncollectible accounts written off	—	(655)	—
Allowance for doubtful accounts, end of period	$ 9,898	$ 9,692	$ 9,114

Prepaid expenses and other assets

Amounts recorded in *Prepaid expenses and other assets* on the Consolidated Balance Sheets are expected to be realized within one year. The following table provides the primary components (in thousands):

	December 31,	
	2019	2018
Derivatives – current (1)	$ 7,266	$ 60,687
Unamortized bonds/insurance premiums	4,357	5,197
Prepaid deposits related to royalties	7,980	8,872
Prepayment to vendors	10,202	864
Other	886	786
Prepaid expenses and other assets	$ 30,691	$ 76,406

(1) Includes both open and closed contracts.

Properties and Equipment

We use the full-cost method of accounting for oil and natural gas properties and equipment, which are recorded at cost. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and natural gas properties are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire properties. Exploration costs include costs of drilling exploratory wells and external geological and geophysical costs, which mainly consist of seismic costs. Development costs include the cost of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production, certain geological and geophysical costs and general and administrative costs are expensed in the period incurred.

Oil and natural gas properties included in the amortization base are amortized using the units-of-production method based on production and estimates of proved reserve quantities. In addition to costs associated with evaluated properties and capitalized asset retirement obligations ("ARO"), the amortization base includes estimated future development costs to be incurred in developing proved reserves as well as estimated plugging and abandonment costs, net of salvage value, related to developing proved reserves. Future development costs related to proved reserves are not recorded as liabilities on the balance sheet, but are part of the calculation of depletion expense. Oil and natural gas properties and equipment include costs of unproved properties. The cost of unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as we have made an evaluation that impairment has occurred. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are non-commercial.

Sales of proved and unproved oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

Furniture, fixtures and non-oil and natural gas property and equipment are depreciated using the straight-line method based on the estimated useful lives of the respective assets, generally ranging from five to seven years. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. Repairs and maintenance costs are expensed in the period incurred.

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

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

	December 31,	
	2019	**2018**
Oil and natural gas properties and equipment	$ 8,532,196	$ 8,169,871
Furniture, fixtures and other	20,317	20,228
Total property and equipment	8,552,513	8,190,099
Less accumulated depreciation, depletion and amortization	7,803,715	7,674,678
Oil and natural gas properties and other, net	$ 748,798	$ 515,421

Ceiling Test Write-Down

Under the full-cost method of accounting, we are required to perform a "ceiling test" calculation quarterly, which determines a limit on the book value of our oil and natural gas properties. If the net capitalized cost of oil and natural gas properties (including capitalized ARO) net of related deferred income taxes exceeds the ceiling test limit, the excess is charged to expense on a pre-tax basis and separately disclosed. Any such write downs are not recoverable or reversible in future periods. The ceiling test limit is calculated as: (i) the present value of estimated future net revenues from proved reserves, less estimated future development costs, discounted at 10%; (ii) plus the cost of unproved oil and natural gas properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base; and (iv) less related income tax effects. Estimated future net revenues used in the ceiling test for each period are based on current prices for each product, defined by the SEC as the unweighted average of first-day-of-the-month commodity prices over the prior twelve months for that period. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials.

We did not record a ceiling test write-down during 2019, 2018 or 2017. If average crude oil and natural gas prices decrease significantly, it is possible that ceiling test write-downs could be recorded during 2020 or in future periods.

Asset Retirement Obligations

We are required to record a separate liability for the present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet. We have significant obligations to plug and abandon well bores, remove our platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site cleanup. Estimating such costs requires us to make judgments on both the costs and the timing of ARO. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. See Note 6 for additional information.

Oil and Natural Gas Reserve Information

We use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period when estimating quantities of proved reserves. Similarly, the prices used to calculate the standardized measure of discounted future cash flows and prices used in the ceiling test for impairment are the 12-month average commodity prices. Proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years, with some limited exceptions allowed. Refer to Note 20 for additional information about our proved reserves.

Derivative Financial Instruments

We have exposure related to commodity prices and have used various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas. We do not enter into derivative instruments for speculative trading purposes. We entered into commodity derivatives contracts during 2019, 2018 and 2017, and as of December 31, 2019, we had open commodity derivative instruments. When we have outstanding borrowings on our revolving bank credit facility, we may use various derivative financial instruments to manage our exposure to interest rate risk from floating interest rates. During 2019, 2018 and 2017, we did not enter into any derivative instruments related to interest rates.

Derivative instruments are recorded on the balance sheet as an asset or a liability at fair value. We have elected not to designate our derivatives instruments as hedging instruments, therefore, all changes in fair value are recognized in earnings. These derivative instruments may or may not have qualified for hedge accounting treatment.

Fair Value of Financial Instruments

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

Income Taxes

We use the liability method of accounting for income taxes in accordance with the *Income Taxes* topic of the Accounting Standard Codification. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. The effects of changes in tax rates and laws on deferred tax balances are recognized in the period in which the new legislation is enacted. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. We classify interest and penalties related to uncertain tax positions in income tax expense. See Note 13 for additional information.

Other Assets (long-term)

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

	December 31,	
	2019	2018
Appeal bond deposits	$ 6,925	$ 6,925
Escrow deposit – Apache lawsuit (Note 18)	—	49,500
Unamortized debt issuance costs	3,798	4,773
Investment in White Cap, LLC	2,590	2,586
Derivatives	2,653	21,275
Unamortized brokerage fee for Monza	3,423	2,277
Proportional consolidation of Monza's other assets (Note 4)	5,308	3,275
ROU assets (Note 7)	7,936	—
Other	814	936
Total other assets	$ 33,447	$ 91,547

Accrued Liabilities

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

	December 31,	
	2019	2018
Accrued interest	$ 10,180	$ 12,385
Accrued salaries/payroll taxes/benefits	2,377	2,320
Incentive compensation plans	9,794	10,817
Litigation accruals	3,673	3,673
Lease liability (Note 7)	2,716	—
Derivatives	1,785	—
Other	371	416
Total accrued liabilities	$ 30,896	$ 29,611

Debt Issued During 2016

We accounted for a debt exchange transaction in 2016, which is described in Note 2, as a troubled debt restructuring pursuant to the guidance under Accounting Standard Codification 470-60, *Troubled Debt Restructuring* ("ASC 470-60"). Under ASC 470-60, the carrying value of the debt issued during 2016 (as described in Note 2) is measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the debt issued in 2016 in the Consolidated Statements of Operations since January 1, 2017 through October 18, 2018. Additionally, interest paid related to the debt issued in 2016 was classified as a financing activity in the Consolidated Statements of Cash Flows as required under ASC 470-60. See Note 2 for additional information.

Debt Issuance Costs

Debt issuance costs associated with the Sixth Amended and Restated Credit Agreement (the "Credit Agreement") are amortized using the straight-line method over the scheduled maturity of the debt. Debt issuance costs associated with all other debt are deferred and amortized over the scheduled maturity of the debt utilizing the effective interest method. Unamortized debt issuance costs associated with our Credit Agreement is reported within *Other Assets* (noncurrent) and unamortized debt issuance costs associated with our other debt instruments are reported as a reduction in *Long-term debt – carrying value* in the Consolidated Balance Sheets. See Note 2 for additional information.

Discounts Provided on Debt Issuance

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

Gain on Debt Transactions

During 2018, the refinancing of our capital structure resulted in a gain of $47.1 million as a result of writing off the carrying value adjustments related to the debt issued in 2016, partially offset by premiums paid to repurchase and retire, repay or redeem all of our prior debt instruments. During 2017, differences in the utilization of the payment-in-kind option resulted in a gain. See Note 2 for additional information.

Other Liabilities (long-term)

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

	December 31,	
	2019	**2018**
Dispute related to royalty deductions	$ 4,687	$ 4,687
Dispute related to royalty-in-kind	250	2,235
Lease liability (Note 7)	4,419	—
Apache lawsuit (Note 18)	—	49,500
Uncertain tax positions including interest/penalties (Note 13)	—	11,523
Other	632	745
Total other liabilities (long-term)	$ 9,988	$ 68,690

Share-Based Compensation

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

Other Expense (Income), Net

For 2019, the amount consists primarily of federal royalty obligation reductions claimed in the current year related to capital deductions from prior periods, and partially offset by expenses related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program (as defined in Note 4). For 2018, the amount consists primarily of credits related to the de-recognition of certain liabilities that had exceeded the statute of limitations, partially offset by expense related to the amortization of the brokerage fee paid in connection with the Joint Venture Drilling Program. For 2017, the amount consists primarily of expense items related to the Apache Corporation ("Apache") lawsuit, partially offset by loss-of-use reimbursements from a third-party for damages incurred at one of our platforms.

Earnings Per Share

Unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per share under the two-class method when the effect is dilutive. See Note 14 for additional information.

Recent Accounting Developments

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-13, *Financial Instruments – Credit Losses* (*Topic 326*) ("ASU 2016-13") and subsequently issued additional guidance on this topic. The new guidance eliminates the probable recognition threshold and broadens the information to consider past events, current conditions and forecasted information in estimating credit losses. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019 and early adoption is permitted for fiscal years beginning after December 15, 2018. Our assessment is this amendment will not have a material impact on our financial statements.

In August 2017, the FASB issued Accounting Standards Update No. 2017-12, *Derivatives and Hedging (Topic 815) – Targeted Improvements to Accounting for Hedging Activities* ("ASU 2017-12") and subsequently issued additional guidance on this topic. The amendments in ASU 2017-12 require an entity to present the earnings effect of the hedging instrument in the same income statement line in which the earning effect of the hedged item is reported. This presentation enables users of financial statements to better understand the results and costs of an entity's hedging program. Also, relative to current GAAP, this approach simplifies the financial statement reporting for qualifying hedging relationships. ASU 2017-12 is effective for fiscal years beginning after December 15, 2019 and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, including adoption in an interim period. As we do not designate our commodity derivative instruments as qualifying hedging instruments, our assessment is this amendment will not impact the presentation of the changes in fair values of our commodity derivative instruments on our financial statements.

2. Long-Term Debt

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

	December 31,	
	2019	2018
Credit Agreement borrowings	$ 105,000	$ 21,000
Senior Second Lien Notes:		
Principal	625,000	625,000
Unamortized debt issuance costs	(10,467)	(12,465)
Total Senior Second Lien Notes	614,533	612,535
Total long-term debt	$ 719,533	$ 633,535

Aggregate annual maturities of amounts recorded for long-term debt as of December 31, 2019 are as follows (in millions): 2020–$0.0; 2021–$0.0; 2022–$105.0; 2023-$625.0. See below for a discussion of our debt instruments.

9.75% Senior Second Lien Notes Due 2023

On October 18, 2018, we entered into a series of transactions to effect a refinancing of substantially all of our outstanding indebtedness. At that time, we issued $625.0 million of 9.75% Senior Second Lien Notes due 2023 (the "Senior Second Lien Notes"), which were issued at par with an interest rate of 9.75% per annum that matures on November 1, 2023, and are governed under the terms of the Indenture of the Senior Second Lien Notes (the "Indenture") dated as of October 18, 2018, entered into by and among the Company, the Guarantors, and Wilmington Trust, National Association, as trustee (the "Trustee"). The estimated annual effective interest rate on the Senior Second Lien Notes was 10.3%, which includes debt issuance costs. Interest on the Senior Second Lien Notes is payable in arrears on May 1 and November 1 of each year.

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

On and after November 1, 2020, we may redeem the Senior Second Lien Notes, in whole or in part, at redemption prices (expressed as percentages of the principal amount thereof) equal to 104.875% for the 12-month period beginning November 1, 2020, 102.438% for the 12-month period beginning November 1, 2021, and 100.000% on November 1, 2022 and thereafter, plus accrued and unpaid interest, if any, to the redemption date. The Senior Second Lien Notes are guaranteed by W&T Energy VI and W & T Energy VII, LLC (together, the "Guarantor Subsidiaries"). If we experience certain change of control events, we will be required to offer to repurchase the notes at 101.000% of the principal amount, plus accrued and unpaid interest, if any, to the repurchase date.

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

The Senior Second Lien Notes are secured by a second-priority lien on all of our assets that are secured under the Credit Agreement (defined below). The Senior Second Lien Notes contain covenants that limit or prohibit our ability and the ability of certain of our subsidiaries to: (i) make investments; (ii) incur additional indebtedness or issue certain types of preferred stock; (iii) create certain liens; (iv) sell assets; (v) enter into agreements that restrict dividends or other payments from the Company's restricted subsidiaries to the Company; (vi) consolidate, merge or transfer all or substantially all of the assets of the Company; (vii) engage in transactions with affiliates; (viii) pay dividends or make other distributions on capital stock or subordinated indebtedness; and (ix) create unrestricted subsidiaries that would not be restricted by the covenants of the Indenture. These covenants are subject to exceptions and qualifications set forth in the Indenture. In addition, most of the above described covenants will terminate if both S&P Global Ratings, a division of S&P Global Inc., and Moody's Investors Service, Inc. assign the Senior Second Lien Notes an investment grade rating and no default exists with respect to the Senior Second Lien Notes.

Credit Agreement

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

- The initial borrowing base is $250.0 million.
- Letters of credit may be issued in amounts up to $30.0 million, provided availability under the Credit Agreement exists.
- The Leverage Ratio, as defined in the Credit Agreement, is limited to 3.00 to 1.00 for quarters ending December 31, 2019 and thereafter. In the event of a Material Acquisition, as defined in the Credit Agreement, the Leverage Ratio limit is 3.50 to 1.00 for the two quarters following a Material Acquisition. The acquisition of the Mobile Bay Properties, as described in Note 5, qualifies as a Material Acquisition under the Credit Agreement.
- The Current Ratio, as defined in the Credit Agreement, must be maintained at greater than 1.00 to 1.00.
- We are required to have deposit accounts only with banks under the Credit Agreement with certain exceptions.
- To the extent there are borrowings, the Applicable Margins, as defined in the Credit Agreement, for Eurodollar Loans range from 2.50% to 3.50% per annum and the Applicable Margins for ABR loans range from 1.50% to 2.50% per annum. The specific Applicable Margin rate is based on the Borrowing Base Utilization Percentage.
- The commitment fee is 37.5 basis points if the Borrowing Base Utilization Percentage is below 50% and 50 basis points if the Borrowing Base Utilization Percentage is 50% or greater.
- We were required to have derivative contracts for a minimum of 50% of projected production for 18 months based on existing proved developed producing reserves and certain other criteria by December 2, 2018 and have met this requirement. We may enter into derivative contracts with counter parties within the Credit Agreement or with other counter parties meeting certain criteria described in the Credit Agreement.

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

Borrowings outstanding under the Credit Agreement are reported in the table above. As of December 31, 2019 and 2018, we had $5.8 million and $9.6 million, respectively, outstanding in letters of credit under the Credit Agreement. The estimated annual effective interest rate on borrowings, exclusive of debt issuance costs, commitment fees and other fees was 4.9%.

As of December 31, 2019, we were in compliance with all applicable covenants of the Credit Agreement and Senior Second Lien Notes.

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

Refinancing Transaction in 2018

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

Prior Debt Instruments

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

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

Exchange Transaction in 2016

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

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

3. Fair Value Measurements

Under GAAP, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether using an in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company's credit risk.

Valuation techniques are generally classified into three categories: the market approach; the income approach; and the cost approach. The selection and application of one or more of these techniques requires significant judgment and is primarily dependent upon the characteristics of the asset or liability, the principal (or most advantageous) market in which participants would transact for the asset or liability and the quality and availability of inputs. Inputs to valuation techniques are classified as either observable or unobservable within the following hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities.
- Level 2 – inputs other than quoted prices that are observable for an asset or liability. These include: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).
- Level 3 – unobservable inputs that reflect our expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

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

	December 31, 2019	December 31, 2018
Assets:		
Derivatives instruments - open contracts, current	$ 6,921	$ 74,580
Derivatives instruments - open contracts, long-term	2,653	—
Liabilities:		
Derivatives instruments - open contracts, current	1,785	—

	December 31, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Liabilities:				
Credit Agreement	$ 105,000	$ 105,000	$ 21,000	$ 21,000
Senior Second Lien Notes	614,533	597,188	612,535	546,875

As of December 31, 2019 and 2018, the carrying value of our open derivative contracts equaled the estimated fair value. We measure the fair value of our derivative contracts by applying the income approach using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used to measure the fair value of our derivative contracts are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads and published commodity future prices.

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

4. Joint Venture Drilling Program

In March 2018, W&T and two other initial members formed and initially funded Monza, which jointly participates with us in the exploration, drilling and development of certain drilling projects (the "Joint Venture Drilling Program") in the Gulf of Mexico. Subsequent to the initial closing, additional investors joined as members of Monza during 2018 and total commitments by all members, including W&T's commitment outside of Monza, are $361.4 million. Through December 31, 2019, nine wells have been completed of which eight were producing as of December 31, 2019. W&T contributed 88.94% of its working interest in certain identified undeveloped drilling projects to Monza and retained 11.06% of its working interest. The Joint Venture Drilling Program is structured so that we initially receive an aggregate of 30.0% of the revenues less expenses, through both our direct ownership of our working interest in the projects and our indirect interest through our interest in Monza, for contributing 20.0% of the estimated total well costs plus associated leases and providing access to available infrastructure at agreed-upon rates. Any exceptions to this structure are approved by the Monza board. W&T is the operator for seven of the nine wells completed through December 31, 2019.

The members of Monza are made up of third-party investors, W&T and an entity owned and controlled by Mr. Tracy W. Krohn, our Chairman and Chief Executive Officer. The Krohn entity invested as a minority investor on the same terms and conditions as the third-party investors, and its investment is limited to 4.5% of total invested capital within Monza. The entity affiliated with Mr. Krohn has made a capital commitment to Monza of $14.5 million.

Monza is an entity separate from any other entity with its own separate creditors who will be entitled, upon its liquidation, to be satisfied out of Monza's assets prior to any value in Monza becoming available to holders of its equity. The assets of Monza are not available to pay creditors of the Company and its affiliates.

Through December 31, 2019, members of Monza made partner capital contributions, including our contributions of working interest in the drilling projects, to Monza totaling $273.3 million and received cash distributions totaling $30.2 million. Our net contribution to Monza, reduced by distributions received, as of December 31, 2019 was $59.7 million. W&T is obligated to fund certain cost overruns to the extent they occur, subject to certain exceptions, for the Joint Venture Drilling Program wells above budgeted and contingency amounts, of which the total exposure cannot be estimated at this time.

Consolidation and Carrying Amounts

Our interest in Monza is considered to be a variable interest that we account for using proportional consolidation. Through December 31, 2019, there have been no events or changes that would cause a redetermination of the variable interest status. We do not fully consolidate Monza because we are not considered the primary beneficiary. As of December 31, 2019, in the Consolidated Balance Sheet, we recorded $16.1 million, net, in *Oil and natural gas properties and other, net*, $5.3 million in *Other assets,* $0.1 million in ARO and $2.7 million, net, increase in working capital in connection with our proportional interest in Monza's assets and liabilities. As of December 31, 2018, in the Consolidated Balance Sheet, we recorded $8.8 million, net, in *Oil and natural gas properties and other, net*, $3.3 million in *Other assets* and $0.7 million, net, increase in working capital in connection with our proportional interest in Monza's assets and liabilities. Additionally, during 2019 and 2018, we called on Monza to provide cash to fund its portion of certain Joint Venture Drilling Program projects in advance of capital expenditure spending, and the unused balances as of December 31, 2019 and 2018 were $5.3 million and $20.6 million, respectively, which are included in the Consolidated Balance Sheet in *Advances from joint interest partners*. For 2019, in the Consolidated Statement of Operations, we recorded $11.9 million in *Total revenues* and $7.4 million in *Operating costs and expenses* in connection with our proportional interest in Monza's operations. For 2018, in the Consolidated Statement of Operations, we recorded $4.3 million in *Total revenues,* $2.3 million in *Operating costs and expenses* and $0.2 million, net, in *Other expense (income), net* in connection with our proportional interest in Monza's operations.

5. Acquisitions and Divestitures

Mobile Bay Properties

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

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

Magnolia Field

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

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

Heidelberg Field

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

Permian Basin

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

6. Asset Retirement Obligations

Asset retirement obligations associated with the retirement and decommissioning of tangible long-lived assets are required to be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The fair value of the ARO is measured using expected cash outflows associated with the ARO, discounted at our credit-adjusted risk-free rate when the liability is initially recorded. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

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

	Year Ended December 31,	
	2019	2018
Asset retirement obligations, beginning of period	$ 310,137	$ 300,446
Liabilities settled	(11,443)	(28,617)
Accretion of discount	19,460	18,431
Liabilities incurred and assumed through acquisition	29,887	4,286
Revisions of estimated liabilities (1) (2)	7,553	15,591
Asset retirement obligations, end of period	355,594	310,137
Less current portion	21,991	24,994
Long-term	$ 333,603	$ 285,143

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

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

7. Leases

ASU 2016-02 was effective for us on January 1, 2019 and we adopted the new standard using a modified retrospective approach. Consequently, upon transition, we recognized a ROU asset and a lease liability. The adoption of the new standard did not impact our Consolidated Statements of Operations, Consolidated Statements of Cash Flows or Consolidated Statements of Changes in Shareholders' Deficit

As provided for in subsequent accounting standards updates related to ASU 2016-02, we are applying the following practical expedients which provide elections to:

- not apply the recognition requirements to short-term leases (a lease that at commencement date has an expected term of 12 months or less and does not contain a purchase option);
- not reassess whether a contract contains a lease, lease classifications between operating and financing and accounting for initial direct costs related to leases;
- not reassess certain land easements in existence prior to January 1, 2019;
- use hindsight in determining the lease term and assessing impairment; and
- not separate non-lease and lease components.

During 2019, various pipeline rights-of-way contracts and a land lease were acquired, assumed, renewed or otherwise entered into, primarily in conjunction with acquiring the Mobile Bay Properties. For these contracts and the existing office lease with future payments, a ROU asset and a corresponding lease liability was calculated based on our assumptions of the term, inflation rates and incremental borrowing rates. The term of each pipeline right-of-way contract is 10 years with various effective dates, and each has an option to renew for up to another ten years. It is expected renewals beyond 10 years can be obtained as renewals were granted to the previous lessees. The land lease has an option to renew every five years extending to 2085. The expected term of the rights-of way and land leases was estimated to approximate the life of the related reserves. The expected term for the office lease was based on management's plans. We recorded ROU assets and lease liabilities using a discount rate of 9.75% for the office lease and 10.75% for the other leases due to their longer expected term.

Minimum future lease payments were estimated assuming expected terms of the leases and estimated inflation escalations of payments for certain leases. Undiscounted future minimum payments as of December 31, 2019 are as follows: 2020 - $2.9 million; 2021 - $0.3 million; 2022 - $0.3 million; 2023 - $0.5 million; and 2024 and beyond - $11.0 million. During 2019, 2018 and 2017, expense recognized related to these right-of-way and office space leases was $2.9 million, $3.4 million and $3.0 million, respectively. The following table provides the amounts included in our Consolidated Balance Sheet related to these leases (in thousands):

	December 31, 2019
ROU assets	$ 7,936
Lease liability:	
Accrued liabilities	$ 2,716
Other liabilities	4,419
Total lease liability	$ 7,135

During 2019, we incurred short-term lease costs related to drilling rigs of $22.2 million, net to our interest, of which the majority of such costs were recorded within *Oil and natural gas properties, net*, on the Consolidated Balance Sheet.

8. Insurance Reimbursements

During 2017, we received insurance reimbursements of $31.7 million related to hurricane damage incurred in prior years. Cash receipts from insurance proceeds are included within *Net cash provided by operating activities* in the Consolidated Statements of Cash Flows and are primarily recorded as reductions in *Oil and natural gas properties and other, net* on the Consolidated Balance Sheets, with some amounts recorded as reductions in *Lease operating expense*, *General and administrative expenses* and *Other income (expense), net* in the Consolidated Statements of Operations. No insurance reimbursements were received during 2019 and 2018, and as of December 31, 2019, there were no significant outstanding insurance claims.

9. Restricted Deposits for ARO

Restricted deposits as of December 31, 2019 and 2018 consisted of funds escrowed for collateral related to the future plugging and abandonment obligations of certain oil and natural gas properties.

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

10. Derivative Financial Instruments

During 2019, 2018 and 2017, we entered into commodity contracts for crude oil and natural gas which related to a portion of our expected production for the time frames covered by the contracts. The crude oil contracts were based on West Texas Intermediate ("WTI") crude oil prices as quoted off the New York Mercantile Exchange ("NYMEX"). The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX. The open contracts as of December 31, 2019 are presented in the following tables:

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

Beginning Period	Termination Period	Notional Quantity (Bbls/day) (1)	Notional Quantity (Bbls) (1)	Strike Price
January 2020	May 2020	10,000	1,520,000	$ 61.00
June 2020	December 2020	10,000	2,140,000	$ 67.50

Crude Oil: Swap, Priced off WTI (NYMEX)

Beginning Period	Termination Period	Notional Quantity (Bbls/day) (1)	Notional Quantity (Bbls) (1)	Strike Price
January 2020	May 2020	1,500	228,000	$ 60.80
January 2020	May 2020	5,000	760,000	$ 61.00
January 2020	May 2020	3,500	532,000	$ 60.85

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

Beginning Period	Termination Period	Notional Quantity (Bbls/day) (1)	Notional Quantity (Bbls) (1)	Put Option Strike Price (Bought)	Call Option Strike Price (Sold)
June 2020	December 2020	9,000	1,926,000	$ 45.00	$ 63.50
June 2020	December 2020	1,000	214,000	$ 45.00	$ 63.60

(1) Bbls = Barrels

Natural Gas Calls - Bought, Priced off Henry Hub (NYMEX)				
Beginning Period	**Termination Period**	**Notional Quantity (MMBtu/day) (2)**	**Notional Quantity (MMBtu) (2)**	**Strike Price**
January 2020	December 2022	40,000	43,840,000	$ 3.00

(2) MMBtu = Million British Thermal Units

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

	December 31,	
	2019	**2018**
Prepaid and other assets – current	$ 7,266	$ 60,687
Other assets – non-current	2,653	21,275
Accrued liabilities	1,785	—

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

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Derivative loss (gain)	$ 59,887	$ (53,798)	$ (4,199)

Cash receipts (payments), net, on commodity derivative contract settlements, which include derivative premium payments, are included within *Net cash provided by operating activities* on the Consolidated Statements of Cash Flows and were as follows (in thousands):

	Year Ended December 31,		
	2019	**2018**	**2017**
Derivative cash receipts (payments), net	$ 13,941	$ (28,164)	$ 4,199

11. Share-Based Awards and Cash-Based Awards

Incentive Compensation Plan

The W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, and subsequent amendments, (the "Plan") was approved by our shareholders. The Plan covers the Company's eligible employees and consultants and includes both cash and share-based compensation awards. The Plan grants the Compensation Committee of the Board of Directors administrative authority over all participants, and grants the CEO with authority over the administration of awards granted to participants that are not subject to section 16 of the Exchange Act (as applicable, the "Compensation Committee").

Pursuant to the terms of the Plan, the Compensation Committee establishes the vesting or performance criteria applicable to the award and may use a single measure or combination of business measures as described in the Plan. Also, individual goals may be established by the Compensation Committee. Performance awards may be granted in the form of stock options, stock appreciation rights, restricted stock, restricted stock units ("RSUs"), bonus stock, dividend equivalents, or other awards related to stock, and awards may be paid in cash, stock, or any combination of cash and stock, as determined by the Compensation Committee. The performance awards granted under the Plan can be measured over a performance period of up to 10 years and annual incentive awards (a type of performance award) will generally be paid within 90 days following the applicable year end.

Share-based Awards: Restricted Stock Units

During 2019, 2018 and 2017, the Company granted RSUs under the Plan to certain of its employees. RSUs are a long-term compensation component and are granted to certain employees, and are subject to satisfaction of certain predetermined performance criteria and adjustments at the end of the applicable performance period based on the results achieved.

As of December 31, 2019, there were 10,874,043 shares of common stock available for issuance in satisfaction of awards under the Plan. The shares available for issuance are reduced on a one-for-one basis when RSUs are settled in shares of common stock, net of withholding tax through the withholding of shares. The Company has the option following vesting to settle RSUs in stock or cash, or a combination of stock and cash. During 2019 and 2018, only shares of common stock were used to settle all vested RSUs. During 2017, cash was used to settle vested RSUs related to the retirement of an executive officer and shares of common stock were used to settle all other vested RSUs. The Company expects to settle RSUs that vest in the future using shares of common stock.

RSUs currently outstanding relate to the 2019 and 2018 grants, which were subject to predetermined performance criteria applied against the applicable performance period. These RSUs continue to be subject to employment-based criteria and vesting generally occurs in December of the second year after the grant. See the table below for anticipated vesting by year.

We recognize compensation cost for share-based payments to employees over the period during which the recipient is required to provide service in exchange for the award. Compensation cost is based on the fair value of the equity instrument on the date of grant. The fair values for the RSUs granted during 2019, 2018 and 2017 were determined using the Company's closing price on the grant date. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that are expected to actually vest.

All RSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restricted period.

During 2019, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) net income before net interest expense; income tax (benefit) expense; depreciation, depletion, amortization and accretion; unrealized commodity derivative gain or loss; amortization of derivative premiums; bad debt reserve; litigation; and other ("Adjusted EBITDA") for 2019 and (ii) Adjusted EBITDA as a percent of total revenue ("Adjusted EBITDA Margin") for 2019. Adjustments range from 0% to 100% based upon actual results compared against pre-defined performance levels. For 2019, the Company achieved below target and above threshold for both Adjusted EBITDA and Adjusted EBITDA Margin, therefore only a portion of the amount granted will be eligible for vesting.

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

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

A summary of activity related to RSUs is as follows:

	2019		2018		2017	
	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share	Restricted Stock Units	Weighted Average Grant Date Fair Value Per Share
Nonvested, beginning of period	3,355,917	$ 3.90	5,765,251	$ 2.48	6,107,248	$ 2.73
Granted	994,698	4.51	988,955	6.90	2,128,879	2.76
Vested	(1,475,373)	2.76	(2,261,665)	2.21	(2,108,553)	3.45
Forfeited	(1,260,520)	3.37	(1,136,624)	2.68	(362,323)	2.87
Nonvested, end of period	1,614,722	$ 5.73	3,355,917	$ 3.90	5,765,251	$ 2.48

Subject to the satisfaction of service conditions, the RSUs outstanding as of December 31, 2019 are eligible to vest in the year indicated in the table below:

	Restricted Stock Units
2020	821,656
2021	793,066
Total	1,614,722

RSUs fair value at grant date - During 2019, 2018 and 2017, the grant date fair value of RSUs granted was $4.5 million, $6.8 million and $5.9 million, respectively.

RSUs fair value at vested date - The fair value of the RSUs that vested during 2019, 2018 and 2017 was $7.0 million, $11.0 million and $5.5 million, respectively, based on the Company's closing price on the vesting date.

Share-Based Awards: Restricted Stock

Under the Directors Compensation Plan, shares of restricted stock ("Restricted Shares") were issued in 2019, 2018 and 2017 to the Company's non-employee directors as a component of their compensation arrangement. Vesting occurs upon completion of the specified vesting period and one-third of each grant vests each year over a three-year period. The holders of Restricted Shares generally have the same rights as a shareholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. Restricted Shares are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restriction period.

As of December 31, 2019, there were 82,620 shares of common stock available for issuance in satisfaction of awards under the Directors Compensation Plan. Reductions in shares available are made when Restricted Shares are granted.

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

	2019		2018		2017	
	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, beginning of period	181,832	$ 3.08	246,528	$ 2.27	161,296	$ 3.47
Granted	46,360	6.04	41,544	6.74	147,372	1.90
Vested	(105,012)	2.67	(106,240)	2.64	(62,140)	4.51
Nonvested, end of period	123,180	$ 4.55	181,832	$ 3.08	246,528	$ 2.27

Subject to the satisfaction of service conditions, the Restricted Shares outstanding as of December 31, 2019 are expected to vest as follows:

	Restricted Shares
2020	78,428
2021	29,304
2022	15,448
Total	123,180

Restricted stock fair value at grant date - The grant date fair value of restricted stock granted during 2019, 2018 and 2017 was $0.3 million each year for all years presented based on the Company's closing price on the date of grant.

Restricted stock fair value at vested date - The fair value of the restricted stock that vested during 2019, 2018 and 2017 was $0.5 million, $0.7 million and $0.1 million, respectively, based on the Company's closing price on the date of vesting.

Share-Based Compensation

A summary of compensation expense under share-based payment arrangements is as follows (in thousands):

	Year Ended December 31, 2019	2018	2017
Share-based compensation expense from:			
Restricted stock units	$ 3,410	$ 3,260	$ 7,785
Restricted stock	280	280	280
Total	$ 3,690	$ 3,540	$ 8,065

As of December 31, 2019, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $5.1 million and $0.4 million, respectively. Unrecognized compensation expense will be recognized through November 2021 for our RSUs and April 2022 for our Restricted Shares.

Cash-based Awards

In addition to share-based compensation, short-term, cash-based awards were granted under the Plan to substantially all eligible employees in 2019, 2018 and 2017. The short-term, cash-based awards, which are generally a short-term component of the Plan, are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. In addition, these cash-based awards included an additional financial condition requiring Adjusted EBITDA less reported Interest Expense Incurred for any fiscal quarter plus the three preceding quarters to exceed defined levels measured over defined time periods for each cash-based award. During 2018, long-term, cash awards were granted to certain employees subject to pre-define performance criteria. Expense is recognized over the service period once the business criteria, individual performance criteria and financial condition are met.

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

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

- For the 2018 long-term, cash-based awards, incentive compensation expense was determined based on the Company achieving certain performance metrics for 2018 and is being recognized over the September 2018 to November 2020 period (the service period of the award). The 2018 long-term, cash-based awards will be eligible for payment on December 14, 2020 subject to participants meeting certain employment-based criteria.

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

- For the 2017 short-term, cash-based awards, incentive compensation expense was determined based on the Company achieving certain performance metrics for 2017 combined with individual performance criteria for 2017 and was recognized over the January 2017 to February 2018 period. The 2017 short term, cash-based awards were paid during March 2018.

Share-Based Awards and Cash-Based Awards Compensation Expense

A summary of compensation expense related to share-based awards and cash-based awards is as follows (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Share-based compensation included in:			
General and administrative	$ 3,690	$ 3,540	$ 8,065
Cash-based incentive compensation included in:			
Lease operating expense	2,206	3,596	2,101
General and administrative	8,897	9,586	5,032
Total charged to operating income	$ 14,793	$ 16,722	$ 15,198

12. Employee Benefit Plan

We maintain a defined contribution benefit plan (the “401(k) Plan”) in compliance with Section 401(k) of the Internal Revenue Code (“IRC”), which covers those employees who meet the 401(k) Plan’s eligibility requirements. From March 5, 2016 to March 1, 2017, the Company suspended matching contributions. During the time periods where matching occurred, the Company’s matching contribution was 100% of each participant’s contribution up to a maximum of 6% of the participant’s eligible compensation, subject to limitations imposed by the IRC. The 401(k) Plan provides 100% vesting in Company match contributions on a pro rata basis over five years of service (20% per year). Our expenses relating to the 401(k) Plan were $2.0 million, $2.0 million, and $1.4 million for 2019, 2018 and 2017, respectively.

13. Income Taxes

Income Tax (Benefit) Expense

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

	Year Ended December 31,		
	2019	2018	2017
Current	$ (11,092)	$ 35	$ (12,786)
Deferred	(64,102)	500	217
Total income tax (benefit) expense	$ (75,194)	$ 535	$ (12,569)

Reconciliation

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

	Year Ended December 31,		
	2019	2018	2017
Income tax (benefit) expense at the federal statutory rate	$ (233)	$ 52,366	$ 23,490
Compensation adjustments	971	457	664
State income taxes	(175)	560	63
Uncertain tax position	(11,523)	—	—
Impact of U.S. tax reform	—	487	105,933
Gain on exchange of debt	—	—	(24,981)
Valuation allowance	(64,704)	(53,980)	(118,643)
Other	470	645	905
Total income tax (benefit) expense	$ (75,194)	$ 535	$ (12,569)

Our effective tax rate for the years 2019, 2018 and 2017 differed from the applicable federal statutory rate of 21.0% for 2019 and 2018 and 35.0% for 2017 primarily due to the impact of the valuation allowance on our deferred tax assets, which is discussed below. As a result, effective tax rates for the years presented above are not meaningful.

Deferred Tax Assets and Liabilities

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities were as follows (in thousands):

	December 31, 2019	December 31, 2018
Deferred tax liabilities:		
Property and equipment	$ 21,647	$ —
Derivatives	—	11,139
Investment in non-consolidated entity	14,716	6,875
Other	2,283	812
Total deferred tax liabilities	38,646	18,826
Deferred tax assets:		
Property and equipment	—	3,934
Derivatives	1,409	—
Asset retirement obligations	76,924	65,811
Federal net operating losses	15,265	10,039
State net operating losses	7,393	7,133
Interest expense limitation carryover	48,458	41,814
Share-based compensation	965	583
Valuation allowance	(54,436)	(117,764)
Other	6,584	7,091
Total deferred tax assets	102,562	18,641
Net deferred tax assets (liabilities)	$ 63,916	$ (185)

Income Taxes Receivable

As of December 31, 2019, we have a current income tax receivable of $1.9 million which relates primarily to a net operating loss ("NOL") carryback claim for 2017 that was carried back to prior years. As of December 31, 2018, we had current income taxes receivable of $54.1 million which primarily relates to our NOL carryback claims for the years 2012, 2013 and 2014 that were carried back to prior years. These carryback claims, in addition to the 2017 claim, were made pursuant to IRC Section 172(f) (related to rules regarding "specified liability losses"), which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. During 2019, we received refunds of $51.8 million and made income tax payments of $0.1 million. Additionally, we received $4.5 million in interest income associated with the refunds in 2019. During 2018, we received refunds of $11.1 million and made income tax payments of $0.1 million. During 2017, we received refunds of $11.9 million and made income tax payments of $0.2 million. The refunds received in 2019, 2018 and 2017 were primarily due to the net operating loss carryback claims under Code Section 172 (f).

Net Operating Loss and Interest Expense Limitation Carryover

The table below presents the details of our net operating loss and interest expense limitation carryover as of December 31, 2019 (in thousands):

	Amount	Expiration Year
Federal net operating loss	$ 72,692	2037
State net operating loss	122,155	2026-2038
Interest expense limitation carryover	223,928	N/A

Valuation Allowance

During 2019 and 2018, we recorded a decrease in the valuation allowance of $63.3 million and $53.8 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

Throughout 2019, the Company has been assessing the realizability of our deferred tax assets by considering positive factors such as, when considering the Company's results for the twelve months ended December 31, 2017, 2018 and 2019, the Company has cumulative pre-tax income. Based on the assessment, we determined that the Company's ability to maintain long-term profitability despite near-term changes in commodity prices and operating costs demonstrated that a portion of the Company's net deferred tax assets would more likely than not be realized. During 2019, we released $64.1 million of the valuation allowance, resulting in an income tax benefit in 2019. The portion of the valuation allowance remaining relates to state net operating losses and the disallowed interest limitation carryover under IRC section 163(j). As of December 31, 2019, the Company's valuation allowance was $54.4 million.

On December 22, 2017, the Tax Cuts and Jobs Act ("TCJA") was enacted into law and we applied the guidance in Staff Accounting Bulletin No. 118 when accounting for the enactment-date effects of the TCJA in 2018 and 2017. As a result of the enactment of the TCJA, our net deferred tax assets and its respective valuation allowance were adjusted downwards by $105.9 million as of December 31, 2017. Our Consolidated Statement of Income, Consolidated Balance Sheet and Consolidated Statement of Cash Flow for the year 2017 were not materially impacted as a result of the provisional re-measurement of our net deferred tax assets and its related valuation allowance.

Uncertain Tax Positions

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

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

	December 31,	
	2019	2018
Balance, beginning of period	$ 9,482	$ 9,482
Decrease during the period	(9,482)	—
Balance, end of period	$ —	$ 9,482

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

Years open to examination

The tax years from 2016 through 2019 remain open to examination by the tax jurisdictions to which we are subject.

14. Earnings Per Share

The Company's unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are deemed participating securities and are included in the computation of earnings per share under the two-class method when the effect is dilutive.

The following table presents the calculation of basic and diluted earnings per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2019	2018	2017
Net income	$ 74,086	$ 248,827	$ 79,682
Less portion allocated to nonvested shares	1,371	9,727	3,244
Net income allocated to common shares	$ 72,715	$ 239,100	$ 76,438
Weighted average common shares outstanding	140,583	139,002	137,617
Basic and diluted earnings per common share	$ 0.52	$ 1.72	$ 0.56

15. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2019	2018	2017
Supplemental cash items:			
Cash paid for interest (1)	$ 66,720	$ 61,501	$ 65,873
Cash paid for income taxes	51	138	185
Cash refunds received for income taxes	51,833	11,126	11,906
Cash paid for share-based compensation (2)	—	1,130	874
Cash received for interest income	7,720	2,385	315
Non-cash investing activities:			
Accruals of property and equipment	29,662	18,575	33,003
ARO - additions, dispositions and revisions, net	37,440	19,877	21,245

(1) During 2018 and 2017, cash paid for interest included amounts related to the debt instruments issued during 2016, which were accounted for under ASC 470-60 and recorded against the carrying value of the debt instruments on the Consolidated Balance Sheets and included in *financing activities* on the Consolidated Statements of Cash Flows. No interest was capitalized in the periods presented.

(2) During 2019, only common shares were used to settle vested RSUs and Restricted Shares. During 2018 and 2017, cash was used to settle vested RSUs related to the retirement of executive officers and shares of common stock were used to settle all other vested RSUs and to settle Restricted Shares.

16. Commitments

See Note 7 for information on leases.

Pursuant to the Purchase and Sale Agreement with Total E&P, we may fulfill security requirements related to ARO for certain properties through securing surety bonds, or through making payments to an escrow account under a formula pursuant to the agreement, or a combination thereof, until certain prescribed thresholds are met. Once the threshold is met for that year, excess funds in the escrow account are returned to us. As of December 31, 2019, we had surety bonds related to the agreement with Total E&P totaling $90.7 million and had no amounts in escrow. The threshold escalates to $103.0 million for 2023 in $3.0 million per year increments.

Pursuant to the Purchase and Sale Agreement with Shell Offshore Inc. (“Shell”) related to ARO for certain properties, we have surety bonds that are subject to re-appraisal by either party. As of December 31, 2019, neither party had requested a re-appraisal to be made. The current security requirement of $64.0 million, which we have met, could be increased up to $94.0 million depending on certain conditions and circumstances.

Pursuant to the Purchase and Sale Agreement with Exxon related to ARO for certain properties, we were required to obtain $27.3 million of surety bonds. This amount increases on June 1 of the following years to $30.0 million - 2020; $33.0 million - 2021; $36.3 million - 2022; $40.0 million - 2023; $44.0 million - 2024, and future increases in increments ranging $4.0 million to $9.0 million per year until the total amount reaches $114.0 million in 2034. We may request a redetermination with Exxon every two years by providing certain documentation as provided in the purchase agreement. We are required to maintain this scheduled level of bonds until the properties are fully plugged, abandoned, and restored in accordance with applicable laws and regulations.

Pursuant to the Purchase and Sale Agreement with Conoco related to ARO for certain properties, we were required to obtain $49.0 million of surety bonds and are required to maintain this level of bonds until the properties are fully plugged, abandoned, and restored in accordance with applicable laws and regulations.

During 2019, 2018 and 2017, we had surety bonds primarily related to our decommissioning obligations or ARO. Total expenses related to surety bonds, inclusive of the surety bonds in connection with the Total E&P and Shell agreements described above, were $4.7 million, $5.9 million and $5.7 million during 2019, 2018 and 2017, respectively. The amount of future commitments is dependent on rates charged in the market place and when asset retirements are completed. Estimated future expenses related to surety bonds were based on current market prices and estimates of the timing of asset retirements, of which some wells and structures are estimated to extend to 2065. Future payment estimates are: 2020–$4.6 million; 2021–$4.6 million; 2022–$4.6 million; 2023 - $4.7 million, 2024 - $4.7 million and thereafter–$52.0 million. Future surety bond costs may change due to a number of factors, including changes and interpretations of regulations by the BOEM.

As of December 31, 2019, we had $6.9 million of collateral deposits for certain sureties related to certain surety bonds for appeals submitted to the Interior Board of Land Appeals (the “IBLA”).

In conjunction with the purchase of an interest in the Heidelberg field, we assumed contracts with certain pipeline companies that contain minimum quantities obligations that extend to 2028. For 2019 and 2018, expense recognized for the difference between the quantities shipped and the minimum obligations was $4.5 million and $2.3 million, respectively. As of December 31, 2019, the estimated future costs are: 2020–$3.7 million; 2021–$2.2 million; 2022–$1.6 million; 2023–$1.2 million; 2024 - $0.8 million and thereafter–$1.3 million.

We have no drilling rig commitments as of December 31, 2019.

17. Related Parties

During 2019, 2018 and 2017, there were certain transactions between us and other companies our CEO either controlled or in which he had an ownership interest. Our CEO owns an aircraft that the Company used for business purposes and the CEO used for his personal matters pursuant to his employment contract, and these costs were paid by the Company. Airplane services transactions were approximately $1.2 million, $1.3 million and $1.2 million for the years 2019, 2018 and 2017, respectively. Our CEO has ownership interests in certain wells operated by us (such ownership interests pre-date our initial public offering). Revenues are disbursed and expenses are collected in accordance with ownership interest. Proportionate insurance premiums were paid to us and proportionate collections of insurance reimbursements attributable to damage on certain wells were disbursed. A company that provides marine transportation and logistics services to W&T employs the spouse of our CEO. The rates charged for these marine and transportation services were either equal to or below rates charged by non-related, third-party companies. Payments to such company totaled $22.8 million, $21.0 million and $22.8 million in 2019, 2018 and 2017, respectively. The spouse received commissions partially based on services rendered to W&T which were approximately $0.2 million in 2019, 2018 and 2017. During 2018, an entity controlled by our CEO participated in the Senior Second Lien Note issuance for an $8.0 million principal commitment on the same terms as the other lenders. See Note 4 for information on a related party transaction concerning Monza.

18. Contingencies

Apache Lawsuit

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

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

Appeal with ONRR

In 2009, we recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited our calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance with the offset to a liability reserve; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the IBLA under the Department of the Interior. On January 27, 2017, the IBLA affirmed the decision of the ONRR requiring W&T to pay approximately $4.7 million in additional royalties. We filed a motion for reconsideration of the IBLA decision on March 27, 2017. Based on a statutory deadline, we filed an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana. We were required to post a bond in the amount of $7.2 million and cash collateral of $6.9 million in order to appeal the IBLA decision. On December 4, 2018, the IBLA denied our motion for reconsideration. On February 4, 2019, we filed our first amended complaint, and the government has filed its Answer in the Administrative Record. On July 9, 2019, we filed an Objection to the Administrative Record and Motion to Supplement the Administrative Record, asking the court to order the government to file a complete privilege log with the record. Following a hearing on July 31, 2019, the Court ordered the government to file a complete privilege log. In an Order dated December 18, 2019, the court ordered the government to produce certain contracts subject to a protective order and to produce the remaining documents in dispute to the court for *in camera* review. We are waiting for the results of that review. Once the issues concerning the administrative record are resolved, the parties will file cross-motions for summary judgment.

Royalties-In-Kind ("RIK")

Under a program of the Minerals Management Service ("MMS") (a Department of Interior ("DOI") agency and predecessor to the ONRR), royalties must be paid "in-kind" rather than in value from federal leases in the program. The MMS added to the RIK program our lease at the East Cameron 373 field beginning in November 2001, where in some months we over delivered volumes of natural gas and under delivered volumes of natural gas in other months for royalties owed. The MMS elected to terminate receiving royalties in-kind in October 2008, causing the imbalance to become fixed for accounting purposes. The MMS ordered us to pay an amount based on its interpretation of the program and its calculations of amounts owed. We disagreed with MMS's interpretations and calculations and filed an appeal with the IBLA, of which the IBLA ruled in MMS' favor. We filed an appeal with the District Court of the Western District of Louisiana, who assigned the case to a magistrate to review and issue a ruling, and the District Court upheld the magistrate's ruling on May 29, 2018. We filed an appeal on July 24, 2018. Part of the ruling was in favor of our position and part was in favor of MMS' position. We appealed the ruling to the U.S. Fifth Circuit Court of Appeals and the government filed a cross-appeal. The Fifth Circuit issued its ruling on December 23, 2019, holding that, while the DOI has statutory authority to switch the method of royalty payment from volumes ("in-kind") to cash ("in value"), the "cashout" methodology that the DOI ordered W&T to implement was unenforceable because that methodology was a "substantive rule" that the DOI adopted in violation of the Administrative Procedure Act. In addition, the Fifth Circuit held that the DOI's claim was unlawfully inflated because DOI improperly failed to give W&T credit for all royalty volumes delivered. The Fifth Circuit remanded the case to the district court to implement the court's decision on appeal. Based on the combination of (i) the DOI's concessions concerning the scope of W&T's liability (e.g., that W&T is only liable for its working interest share of the royalty volumes at issue), and (ii) the Fifth Circuit's ruling, we estimate that the value of the DOI's claim against W&T is no greater than $0.25 million and have adjusted the liability reserve for this matter as of December 31, 2019 to such amount.

Notices of Proposed Civil Penalty Assessment

During 2019 and 2018, we did not pay any civil penalties to the BSEE related to Incidents of Noncompliance ("INCs") at various offshore locations. We currently have nine open civil penalties issued by the BSEE from INCs, which have not been settled as of the filing date of this Form 10-K. The INCs underlying these open civil penalties cite alleged non-compliance with various safety-related requirements and procedures occurring at separate offshore locations on various dates ranging from July 2012 to January 2018. The proposed civil penalties for these INCs total $7.7 million. As of December 31, 2019 and December 31, 2018, we have accrued approximately $3.5 million, which is our best estimate of the final settlements 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. We are exploring the possibility of settling these civil penalties with the BSEE.

Royalties – "Unbundling" Initiative

The ONRR has publicly announced an "unbundling" initiative to revise the methodology employed by producers in determining the appropriate allowances for transportation and processing costs that are permitted to be deducted in determining royalties under Federal oil and gas leases. The ONRR's initiative requires re-computing allowable transportation and processing costs using revised guidance from the ONRR going back 84 months for every gas processing plant that processed our gas. In the second quarter of 2015, pursuant to the initiative, we received requests from the ONRR for additional data regarding our transportation and processing allowances on natural gas production related to a specific processing plant. We also received a preliminary determination notice from the ONRR asserting that our allocation of certain processing costs and plant fuel use at another processing plant was not allowed as deductions in the determination of royalties owed under Federal oil and gas leases. We have submitted revised calculations covering certain plants and time periods to the ONRR. As of the filing date of this Form 10-K, we have not received a response from the ONRR related to our submissions. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under our Federal oil and gas leases for current and prior periods. During 2019, 2018 and 2017, we paid $0.4 million, $0.6 million and $1.6 million, respectively, of additional royalties and expect to pay more in the future. We are not able to determine the range of any additional royalties or if such amounts would be material.

Supplemental Bonding Requirements by the BOEM

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

Surety Bond Issuers' Collateral Requirements

The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for plugging and abandonment activities. We may be required to post collateral at any time pursuant to the terms of our agreement with various sureties under our existing bonds, if they so demand at their discretion. We did not receive any such collateral demands from surety bond providers during 2019 or 2018.

Other Claims

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

19. Selected Quarterly Financial Data—UNAUDITED

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2019				
Revenues	$ 116,080	$ 134,701	$ 132,221	$ 151,894
Operating (loss) income	(30,976)	37,379	35,399	16,847
Net (loss) income (1)	(47,761)	36,389	75,899	9,559
Basic and diluted (loss) earnings per common share	(0.34)	0.25	0.53	0.07
Year Ended December 31, 2018				
Revenues	$ 134,213	$ 149,612	$ 153,459	$ 143,422
Operating income	38,739	48,467	57,147	102,674
Net income (1)	27,640	36,083	46,260	138,844
Basic and diluted earnings per common share	0.19	0.25	0.32	0.96

(1) During 2019, we recorded a derivative loss (gain) of $48.9 million, ($1.8) million, ($5.9) million, and $18.7 million in the first, second, third and fourth quarters, respectively. During 2019, we recorded income tax expense (benefit) of $0.2 million, ($11.7) million, ($55.5) million and ($8.2) million in the first, second, third and fourth quarters, respectively. During the fourth quarter of 2018, we recorded a gain on debt transactions of $47.1 million and a derivative gain of $59.7 million. See Note 2, Note 9 and Note 13 for additional information.

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

20. Supplemental Oil and Gas Disclosures—UNAUDITED

Geographic Area of Operation

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

Capitalized Costs

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

	December 31,		
	2019	2018	2017
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 8,532.2	$ 8,169.9	$ 8,102.0
Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities	(7,793.3)	(7,665.1)	(7,525.0)
Net capitalized costs related to producing activities	$ 738.9	$ 504.8	$ 577.0

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

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

	Year Ended December 31,		
	2019	2018	2017
Costs incurred: (1)			
Proved properties acquisitions	$ 223.8	$ 24.1	$ 1.1
Exploration (2) (3)	30.6	49.9	62.0
Development	114.5	56.2	92.5
Total costs incurred in oil and gas property acquisition, exploration and development activities	$ 368.9	$ 130.2	$ 155.6

(1) Includes net additions from capitalized ARO of $37.5 million, $20.3 million and $21.3 million during 2019, 2018 and 2017, respectively. These adjustments for ARO are associated with acquisitions, liabilities incurred, divestitures and revisions of estimates.

(2) Includes seismic costs of $7.8 million, $1.5 million and $0.5 million incurred during 2019, 2018 and 2017, respectively.

(3) Includes geological and geophysical costs charged to expense of $5.7 million, $5.4 million and $4.2 million during 2019, 2018 and 2017, respectively.

Depreciation, depletion, amortization and accretion expense

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

	Year Ended December 31,		
	2019	2018	2017
Depreciation, depletion, amortization and accretion per Boe	$ 10.01	$ 11.24	$ 10.68

Oil and Natural Gas Reserve Information

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve information represents estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available. Decreases in the prices of oil, NGLs and natural gas could have an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. We are not the operator with respect to 10.7% of our proved developed non-producing reserves as of December 31, 2019 so we may not be in a position to control the timing of all development activities. We are the operator for substantially all of our proved undeveloped reserves as of December 31, 2019. In prior years, we were not the operator of substantially all proved undeveloped reserves.

The following sets forth estimated quantities of our net proved, proved developed and proved undeveloped oil, NGLs and natural gas reserves. All of the reserves are located in the United States with all located in state and federal waters in the Gulf of Mexico. The reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information. In addition to other criteria, estimated reserves are assessed for economic viability based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for the year in accordance with definitions and guidelines set forth by the SEC and the FASB. The prices used do not purport, nor should it be interpreted, to present the current market prices related to our estimated oil and natural gas reserves. Actual future prices and costs may differ materially from those used in determining our proved reserves for the periods presented. The prices used are presented in the section below entitled "*Standardized Measure of Discounted Future Net Cash Flows*".

				Total Energy Equivalent Reserves (1)	
	Oil (MMBbls)	**NGLs (MMBbls)**	**Natural Gas (Bcf)**	**Oil Equivalent (MMBoe)**	**Natural Gas Equivalent (Bcfe)**
Proved reserves as of Dec. 31, 2016	32.9	8.2	197.8	74.0	444.0
Revisions of previous estimates (2)	4.5	0.7	25.8	9.6	57.4
Extensions and discoveries (3)	4.1	0.3	5.4	5.2	31.3
Production	(7.1)	(1.4)	(36.8)	(14.6)	(87.4)
Proved reserves as of Dec. 31, 2017	34.4	7.8	192.2	74.2	445.3
Revisions of previous estimates (4)	11.6	2.8	40.4	21.1	126.7
Extensions and discoveries (5)	0.5	0.3	7.7	2.1	12.6
Purchase of minerals in place (6)	1.5	0.4	9.4	3.4	20.7
Sales of minerals in place (7)	(2.2)	(0.2)	(7.2)	(3.5)	(21.2)
Production	(6.7)	(1.3)	(32.0)	(13.3)	(80.0)
Proved reserves as of Dec. 31, 2018	39.1	9.8	210.5	84.0	504.1
Revisions of previous estimates (8)	1.4	(1.5)	(16.9)	(3.0)	(18.2)
Extensions and discoveries (9)	0.9	0.1	1.2	1.1	6.7
Purchase of minerals in place (10)	3.1	17.4	417.6	90.1	540.9
Production	(6.7)	(1.3)	(41.3)	(14.8)	(89.0)
Proved reserves as of Dec. 31, 2019	37.8	24.5	571.1	157.4	944.5
Year-end proved developed reserves:					
2019	28.0	21.7	504.9	133.8	802.9
2018	31.5	7.8	166.8	67.0	402.2
2017	26.1	7.2	173.5	62.2	373.3
Year-end proved undeveloped reserves:					
2019 (11)	9.8	2.8	66.2	23.6	141.6
2018	7.6	2.0	43.7	17.0	101.9
2017	8.3	0.6	18.7	12.0	72.0

Volume measurements:

MMBbls – million barrels for crude oil, condensate or NGLs

MMBoe – million barrels of oil equivalent

Bcf – billion cubic feet

Bcfe – billion cubic feet of gas equivalent

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

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

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

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

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

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

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

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

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

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

(11) We believe that we will be able to develop all but 2.5 MMBoe (approximately 11%) of the total of 23.6 MMBoe reserves classified as proved undeveloped ("PUDs") at December 31, 2019, within five years from the date such reserves were initially recorded. The lone exceptions are at the Mississippi Canyon 243 field (Matterhorn) and Virgo deepwater fields where future development drilling has been planned as sidetracks of existing wellbores due to conductor slot limitations and rig availability. Two sidetrack PUD locations, one each at Matterhorn and Virgo, will be delayed until an existing well is depleted and available to sidetrack. We also plan to recomplete and convert an existing producer at Matterhorn to water injection for improved recovery following depletion of existing well. Based on the latest reserve report, these PUD locations are expected to be developed in 2021 and 2022.

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to our proved oil and natural gas reserves together with changes therein. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices for the periods presented. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials. Due to the lack of a benchmark price for NGLs, a ratio is computed for each field of the NGLs realized price compared to the crude oil realized price. Then, this ratio is applied to the crude oil price using FASB/SEC guidance. The average commodity prices weighted by field production and after adjustments related to the proved reserves are as follows:

	December 31,			
	2019	2018	2017	2016
Oil - per barrel	$ 58.11	$ 65.21	$ 46.58	$ 36.28
NGLs per barrel	18.72	29.73	22.65	16.82
Natural gas per Mcf	2.63	3.13	2.86	2.47

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

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and natural gas reserves. These estimates reflect proved reserves only and ignore, among other things, future changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2019 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is as follows (in millions):

	Year Ended December 31,		
	2019	2018	2017
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 4,153.8	$ 3,500.9	$ 2,328.8
Future costs:			
Production	(1,901.1)	(958.5)	(813.8)
Development	(297.3)	(272.4)	(157.4)
Dismantlement and abandonment	(497.4)	(355.9)	(361.9)
Income taxes	(170.5)	(293.9)	(74.8)
Future net cash inflows before 10% discount	1,287.5	1,620.2	920.9
10% annual discount factor	(300.6)	(553.2)	(180.3)
Total	$ 986.9	$ 1,067.0	$ 740.6

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

	Year Ended December 31,		
	2019	2018	2017
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 1,067.0	$ 740.6	$ 478.3
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(315.8)	(398.1)	(315.3)
Net changes in price, net of future production costs	(376.4)	571.5	288.0
Extensions and discoveries, net of future production and development costs	27.0	53.6	119.3
Changes in estimated future development costs	(6.0)	(114.7)	(38.9)
Previously estimated development costs incurred	19.3	48.4	102.8
Revisions of quantity estimates	116.4	307.6	106.4
Accretion of discount	107.4	50.5	30.2
Net change in income taxes	62.9	(133.4)	(54.7)
Purchases of reserves in-place	298.3	27.8	—
Sales of reserves in-place	—	(54.1)	—
Changes in production rates due to timing and other	(13.2)	(32.7)	24.5
Net (decrease) increase	(80.1)	326.4	262.3
Standardized measure, end of year	$ 986.9	$ 1,067.0	$ 740.6

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

None.

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

Disclosure Controls and Procedures

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

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have each concluded that as of December 31, 2019 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2019, is set forth in "*Management's Report on Internal Control over Financial Reporting*" included under Part II, Item 8 in this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2019, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included under Part II, Item 8 in this Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K and to the information set forth following Item 3 of this report.

Item 11. ***Executive Compensation***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) Documents filed as a part of this report:

1. Financial Statements. See "Index to Consolidated Financial Statements" in Part II, Item 8 of this Form 10-K.

All schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

2. Exhibits:

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006 (File No. 001-32414))
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
3.4	Form of Certificate of Amendment No. 2 to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2016 (File No. 001-32414))
3.5	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc., dated as of September 6, 2016 (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed September 6, 2016 (File No. 001-32414))
4.1	Specimen Common Stock Certificate (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
4.2	Indenture, dated as of October 18, 2018, by and among W&T Offshore, Inc., W&T Energy VI, LLC, and W&T Energy VII, LLC, as subsidiary guarantors the Guarantors (as defined) and Wilmington Trust, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on October 24, 2018 (File No. 001-32414))
4.3**	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended.

10.1*	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.2*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006 (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed July 12, 2006 (File No. 001-32414))
10.3*	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010 (File No. 001-32414))
10.4*	First Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013 (File No. 001-32414))
10.5*	Second Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed April 3, 2013 (File No. 001-32414))
10.6*	Third Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2016 (File No. 001-32414))
10.7*	Fourth Amendment to W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed March 24, 2017 (File No. 001-32414))
10.8*	Employment Agreement between W&T Offshore, Inc. and Tracy W. Krohn dated as of November 1, 2010 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on November 5, 2010 (File No. 001-32414))
10.9*	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors (Incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 001-32414))
10.10	Purchase Agreement dated October 5, 2018 by and among W&T Offshore, Inc., W&T Energy VI, LLC, W&T Energy VII, LLC and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers named therein. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on October 11, 2018 (File No. 001-32414))
10.11	First Amendment to Intercreditor Agreement, dated as of October 18, 2018, by and among Toronto Dominion (Texas) LLC, as Original Priority Lien Agent, Morgan Stanley Senior Funding, Inc., as Original Second Lien Collateral Trustee, Wilmington Trust, National Association, as Original Second Lien Trustee, Wilmington Trust, National Association, as Second Lien Trustee, Wilmington Trust, National Association, as Second Lien Collateral Trustee, Cortland Capital Market Services LLC, as Priority Lien Agent, Wilmington Trust, National Association as Third Lien Collateral Trustee and Wilmington Trust, National Association as Third Lien Trustee. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on October 24, 2018 (File No. 001-32414))

10.12 Priority Confirmation Joinder, dated as of September 18, 2018, by and between Toronto Dominion (Texas) LLC, as Original Priority Lien Agent, Morgan Stanley Senior Funding, Inc., as Original Second Lien Collateral Trustee, Wilmington Trust, National Association, as Original Second Lien Trustee, Second Lien Collateral Trustee, Third Lien Collateral Trustee and Third Lien Trustee and Cortland Capital Market Services LLC, Priority Lien Agent. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed on October 24, 2018 (File No. 001-32414))

10.13 Sixth Amended and Restated Credit Agreement, dated as of October 18, 2018, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed on October 24, 2018 (File No. 001-32414))

10.14** First Amendment to Sixth Amended and Restated Credit Agreement, dated November 27, 2019, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto.

10.15** Second Amendment to Sixth Amended and Restated Credit Agreement, dated February 24, 2020, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto.

10.16* Form of 2016 Executive Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.10 of the Company's Quarterly Report on Form 10-Q, filed November 3, 2016 (File No. 001-32414))

10.17* Form of 2017 Executive Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q, filed May 4, 2017 (File No. 001-32414))

10.18* Form of Executive Annual Incentive Agreement for Fiscal 2018 (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed November 1, 2018 (File No. 001-32414))

10.19* Form of 2018 Executive Long Term Incentive Agreement (Incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q, filed November 1, 2018 (File No. 001-32414))

10.20* Form of Executive Annual Incentive Award Agreement for Fiscal Year 2019 (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q filed October 31, 2019 (File No. 001-32414)).

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

10.22 Purchase and Sale Agreement, dated as of January 1, 2019, between Exxon Mobil Corporation, Mobil Oil Exploration & Producing Southeast Inc., XH, LLC, Exxon Mobile Bay Limited Partnership, ExxonMobil U.S. Properties Inc. and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q, filed August 1, 2019 (File No. 001-32414))

21.1**	Subsidiaries of the Registrant.
23.1**	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
23.2**	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350.
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Schema Document.
101.CAL**	XBRL Calculation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document.
101.LAB**	XBRL Label Linkbase Document.
101.PRE**	XBRL Presentation Linkbase Document.

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

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry that are used in this report.

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

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

Bcf. Billion cubic feet.

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

Boe. Barrel of oil equivalent.

Boe/d. Barrel of oil equivalent per day.

BOEM. Bureau of Ocean Energy Management. The agency is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

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

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

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

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

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

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

Developed reserves. Oil and natural gas reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

Dry hole or well. A well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. Refers to a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

Extension well. A well drilled to extend the limits of a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

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

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

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

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

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids. These are created during the processing of natural gas.

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

Oil. Crude oil and condensate.

OCS. Outer continental shelf.

OCS block. A unit of defined area for purposes of management of offshore petroleum exploration and production by the BOEM.

ONRR. Office of Natural Resources Revenue. The agency assumed the functions of the former Minerals Revenue Management Program, which had been renamed to the Bureau of Ocean Energy Management, Regulation and Enforcement.

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

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

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, "existing economic conditions" include prices and costs at which economic production from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

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

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

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

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

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

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

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

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

Supra-salt. A geological layer lying above the salt layer.

Undeveloped reserves. Oil and natural gas reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic production at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 5, 2020.

W&T OFFSHORE, INC.

By: /S/ JANET YANG

Janet Yang
Executive Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 5, 2020.

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

Board of Directors

Tracy W. Krohn
Founder, Chairman, Chief Executive Officer and President

Stuart Katz
Presiding Director

Virginia Boulet
Director

S. James Nelson, Jr.
Director

B. Frank Stanley
Director

Executive Officers

Tracy W. Krohn
Founder, Chairman, Chief Executive Officer and President

Janet Yang
Executive Vice President and Chief Financial Officer

William J. Williford
Executive Vice President and General Manager Gulf of Mexico

Stephen L. Schroeder
Senior Vice President and Chief Technical Officer

Shahid A. Ghauri
Vice President, General Counsel and Corporate Secretary

Corporate Office

W&T Offshore, Inc.
Nine Greenway Plaza, Suite 300
Houston, TX 77046
Tel 713.626.8525
www.wtoffshore.com

Registrar & Transfer Agent

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to the transfer agent.

Computershare Investor Services, L.L.C.
2 North La Salle Street
Chicago, IL 60602
Tel 312.588.4990
Web us.computershare.com

Independent Auditors

Ernst & Young LLP, Houston, TX

Independent Petroleum Consultants

Netherland, Sewell & Associates, Inc.
1601 Elm Street, Suite 4500
Dallas, TX 75201-4754

Annual Meeting

The Company's 2019 Annual Meeting of Shareholders will be held at 8 a.m. Central Time on Wednesday, May 6, 2020, at the Corporate Office, Nine Greenway Plaza, Suite 300, Houston, Texas 77046.

Form 10-K & Quarterly Reports / Investor Contact

A copy of the W&T Offshore, Inc. Form 10-K for the year ended December 31, 2019 and quarterly Form 10-Q reports filed with the Securities and Exchange Commission, are available from the Company. Requests for investor-related information should be directed to Investor Relations at the Company's corporate office or on the Internet at www.wtoffshore.com. E-mail: investorrelations@wtoffshore.com. The W&T Offshore, Inc. Form 10-K and quarterly Form 10-Q reports are also available on our Web site at www.wtoffshore.com. The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 301 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to the Form 10-K. Tracy W. Krohn, our Chief Executive Officer, has also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

W&T OFFSHORE

W&T Offshore, Inc.
Nine Greenway Plaza, Suite 300
Houston, TX 77046
www.wtoffshore.com