UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

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

For the quarterly period ended March 31, 2018

or

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

For the transition period from ______________ to _______________

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas **(State of incorporation)**	**72-1121985** **(IRS Employer Identification Number)**
Nine Greenway Plaza, Suite 300 **Houston, Texas** **(Address of principal executive offices)**	**77046-0908** **(Zip Code)**

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Large accelerated filer	☐	Accelerated filer	☑
Non-accelerated filer (Do not check if a smaller reporting company)	☐	Smaller reporting company	☐
		Emerging growth company	☐

Indicate by check mark whether the registrant is a shell company. 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. ☐

As of April 30, 2018, there were 139,091,289 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	March 31, 2018	December 31, 2017
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 130,711	$ 99,058
Receivables:		
Oil and natural gas sales	44,942	45,443
Joint interest	17,835	19,754
Income taxes	65,103	13,006
Total receivables	127,880	78,203
Prepaid expenses and other assets (Note 1)	20,197	13,419
Total current assets	278,788	190,680
Oil and natural gas properties and other, net - at cost: (Note 1)	573,352	579,016
Restricted deposits for asset retirement obligations	25,622	25,394
Income taxes receivable	—	52,097
Other assets (Note 1)	64,414	60,393
Total assets	$ 942,176	$ 907,580
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$ 77,444	$ 83,665
Undistributed oil and natural gas proceeds	22,273	20,129
Asset retirement obligations	25,748	23,613
Long-term debt	22,858	22,925
Accrued liabilities (Note 1)	23,293	17,930
Total current liabilities	171,616	168,262
Long-term debt: (Note 2)		
Principal	889,790	889,790
Carrying value adjustments	77,691	79,337
Long term debt, less current portion - carrying value	967,481	969,127
Asset retirement obligations, less current portion	280,735	276,833
Other liabilities (Note 1)	66,993	66,866
Commitments and contingencies (Note 10)	—	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at March 31, 2018 and December 31, 2017	—	—
Common stock, $0.00001 par value; 200,000,000 shares authorized; 141,960,462 issued and 139,091,289 outstanding at March 31, 2018 and December 31, 2017	1	1
Additional paid-in capital	547,039	545,820
Retained earnings (deficit)	(1,067,522)	(1,095,162)
Treasury stock, at cost; 2,869,173 shares at March 31, 2018 and December 31, 2017	(24,167)	(24,167)
Total shareholders' deficit	(544,649)	(573,508)
Total liabilities and shareholders' deficit	$ 942,176	$ 907,580

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31,	
	2018	2017
	(In thousands except per share data) (Unaudited)	
Revenues:		
Oil	$ 97,306	$ 84,971
NGLs	9,660	8,742
Natural gas	25,867	29,758
Other	1,380	922
Total revenues	134,213	124,393
Operating costs and expenses:		
Lease operating expenses	36,843	40,164
Production taxes	455	515
Gathering and transportation	5,057	6,209
Depreciation, depletion, amortization and accretion	38,081	39,990
General and administrative expenses	15,038	13,274
Derivative gain	—	(3,955)
Total costs and expenses	95,474	96,197
Operating income	38,739	28,196
Interest expense	11,323	11,294
Other (income) expense, net	(333)	191
Income before income tax expense (benefit)	27,749	16,711
Income tax expense (benefit)	109	(7,588)
Net income	$ 27,640	$ 24,299
Basic and diluted earnings per common share	$ 0.19	$ 0.17

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' DEFICIT

	Common Stock Outstanding		Additional Paid-In	Retained Earnings	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	(Deficit)	Shares	Value	Deficit
				(In thousands) (Unaudited)			
Balances at December 31, 2017	139,091	$ 1	$ 545,820	$ (1,095,162)	2,869	$ (24,167)	$ (573,508)
Share-based compensation	—	—	1,219	—	—	—	1,219
Net income	—	—	—	27,640	—	—	27,640
Balances at March 31, 2018	139,091	$ 1	$ 547,039	$ (1,067,522)	2,869	$ (24,167)	$ (544,649)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(In thousands) (Unaudited)	
Operating activities:		
Net income	$ 27,640	$ 24,299
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	38,081	39,990
Amortization of debt items	466	412
Share-based compensation	1,219	1,928
Derivative gain	—	(3,955)
Cash receipts on derivative settlements, net	—	713
Deferred income taxes	109	105
Changes in operating assets and liabilities:		
Oil and natural gas receivables	501	(1,882)
Joint interest receivables	1,919	5,042
Insurance reimbursements	—	30,100
Prepaid expenses and other assets	(6,391)	(7,972)
Asset retirement obligation settlements	(7,022)	(14,499)
Cash advances from JV partners	19,147	(2,531)
Accounts payable, accrued liabilities and other	(688)	9,433
Net cash provided by operating activities	74,981	81,183
Investing activities:		
Investment in oil and natural gas properties and equipment	(21,117)	(23,338)
Changes in operating assets and liabilities associated with investing activities	(17,154)	1,168
Deposit for acquisition	(3,000)	—
Purchases of furniture, fixtures and other	—	(853)
Net cash used in investing activities	(41,271)	(23,023)
Financing activities:		
Payment of interest on 1.5 Lien Term Loan	(2,057)	(2,056)
Other	—	(245)
Net cash used in financing activities	(2,057)	(2,301)
Increase in cash and cash equivalents	31,653	55,859
Cash and cash equivalents, beginning of period	99,058	70,236
Cash and cash equivalents, end of period	$ 130,711	$ 126,095

See Notes to Condensed Consolidated Financial Statements.

1. Basis of Presentation

Operations. W&T Offshore, Inc. (with 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 offshore in the Gulf of Mexico. The Company is active in the exploration, development and acquisition of oil and natural gas properties. Our interests in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. (on a stand-alone basis, the "Parent Company") and its 100%-owned subsidiary, W & T Energy VI, LLC ("Energy VI") and through our proportionately consolidated interest in Monza Energy LLC, as described in more detail below under the subheading "-Recent Events" in this Note and in Note 4 herein.

Interim Financial Statements. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP") for interim periods and the appropriate rules and regulations of the Securities and Exchange Commission ("SEC"). Accordingly, the condensed consolidated financial statements do not include all of the information and footnote disclosures required by GAAP for complete financial statements for annual periods. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included.

Operating results for interim periods are not necessarily indicative of the results that may be expected for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2017.

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 and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Recent Events. The price we receive for our crude oil, natural gas liquids ("NGLs") and natural gas production directly affects our revenues, profitability, cash flows, liquidity, access to capital, proved reserves and future rate of growth. The average realized prices of these commodities improved during the three months ended March 31, 2018 compared to the average realized prices in the three months ended March 31, 2017. Operating costs were lower for the three months ended March 31, 2018 on an absolute basis compared to the three months ended March 31, 2017.

Our Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement") provides our revolver bank credit facility and matures on November 8, 2018. As of March 31, 2018, we had $0.3 million of letters of credit outstanding and no amounts borrowed on our revolving bank credit facility. Our 8.500% Senior Notes (the "Unsecured Senior Notes") mature on June 15, 2019. If the Unsecured Senior Notes have not been extended, refunded, defeased, discharged, replaced or refinanced by February 28, 2019, then the 11.00% 1.5 Lien Term Loan, due November 15, 2019 (the "1.5 Lien Term Loan") and the 8.50%/10.00% Third Lien Payment-In-Kind ("PIK") Toggle Notes, due June 15, 2021, (the "Third Lien PIK Toggle Notes") will both accelerate their maturity to February 28, 2019. During the remainder of 2018, we plan to address the issues of the potential maturity acceleration of these two debt instruments and to extend or replace the revolving bank credit facility. We expect to build sufficient cash balances in 2018 to be able to redeem, repurchase or refinance the Unsecured Senior Notes. Certain amendments under the Credit Agreement and the 1.5 Lien Term Loan will likely be required in the event we redeem or repurchase the Unsecured Senior Notes, which we anticipate would be granted if requested. Assuming we can also repay or refinance the 1.5 Lien Term Loan, then we believe that we would amend our revolving bank credit facility in such a manner that will permit an extension of the maturity of such facility. There can be no assurance that lenders will extend our revolving bank credit facility maturity, but under current market conditions and based on the outlook of our cash position in 2018 and further, we believe our lenders or replacement lenders will be amenable to participating in a refinancing or other corporate financing transaction.

On March 12, 2018, W&T and two initial members formed and initially funded a limited liability company, Monza Energy LLC, a Delaware limited liability company ("Monza"), that will jointly participate with us in the exploration, drilling and development of up to 14 identified drilling projects (the "JV Drilling Program") in the Gulf of Mexico over the next three years. W&T contributed 88.94% of its working interest in the 14 identified projects to Monza and retained an 11.06% working interest. Since the initial closing, additional investors have joined in Monza and as of April 27, 2018, total commitments by all investors are $297.6 million. We anticipate additional investors will join in the program.

In summary, W&T owns a direct interest in the 14 drilling projects as well as an indirect interest via its interest in Monza. The JV Drilling Program is structured so that we initially receive an aggregate of 30.0% of the net revenues, 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. See Note 4 and Note 11 for additional information.

We have assessed our financial condition, the current capital markets and options given different scenarios of commodity prices. We believe we will have adequate available liquidity to fund our operations through May 2019, the period of assessment to qualify as a going concern. However, we cannot predict the potential changes in commodity prices or future Bureau of Ocean Energy Management ("BOEM") bonding requirements, either of which could affect our operations, liquidity levels and compliance with debt covenants.

See our Annual Report on Form 10-K for the year ended December 31, 2017 concerning risks related to our business and events occurring during 2017 and other information and the Notes herein for additional information.

Accounting Standard Updates Effective January 1, 2018. Accounting Standards Update No. 2016-18, ("ASU 2016-18"),*Statement of Cash Flows (Topic 230) – Restricted Cash* became effective for us in the period ending March 31, 2018. As we did not have any amounts recorded as restricted cash in the three months ended March 31, 2018, or any amounts recorded as restricted cash during 2017, ASU 2016-18 did not affect the Condensed Consolidated Statement of Cash Flows.

Accounting Standard Update No. 2014-09, ("ASU 2014-09")*Revenue from Customers (Topic 606)*, became effective for us in the period ending March 31, 2018. We reviewed our contracts using the five-step revenue recognition model, which did not identify any changes required as to the amount or timing of revenue recognition. We adopted the new standard using the modified retrospective approach which did not result in any cumulative-effect adjustment on the date of adoption. The implementation of ASU 2014-09 resulted in a change in our reporting in the Condensed Consolidated Statement of Operations so that we now report revenue streams separately for oil, NGLs, natural gas and other revenues in compliance with the new standard.

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.

Reclassification. Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation as follows: Within the*Net Cash Provided by Operating Activities* of the Condensed Consolidated Statements of Cash Flows, adjustments were made to certain line items, of which did not change the total amount previous reported. The adjustments did not affect the Condensed Consolidated Balance Sheets or the Condensed Consolidated Statements of Operations.

Prepaid Expenses and Other Assets. The amounts recorded are expected to be realized within one year and the major categories are presented in the following table (in thousands):

	March 31, 2018	December 31, 2017
Prepaid/accrued insurance	$ 1,983	$ 2,401
Surety bond unamortized premiums	3,387	2,676
Prepaid deposits related to royalties	7,451	6,456
Deposit related to an acquisition	3,000	—
Proportional consolidation of Monza prepaids (Note 4)	2,399	—
Other	1,977	1,886
Prepaid expenses and other assets	$ 20,197	$ 13,419

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):

	March 31, 2018	December 31, 2017
Oil and natural gas properties and equipment	$ 8,129,924	$ 8,102,044
Furniture, fixtures and other	21,831	21,831
Total property and equipment	8,151,755	8,123,875
Less accumulated depreciation, depletion and amortization	7,578,403	7,544,859
Oil and natural gas properties and other, net	$ 573,352	$ 579,016

Accrued Liabilities. The major categories are presented in the following table (in thousands):

	March 31, 2018	December 31, 2017
Accrued interest	$ 14,889	$ 4,200
Accrued salaries/payroll taxes/benefits	2,577	2,454
Incentive compensation plans	1,993	7,366
Litigation accruals	3,480	3,480
Other	354	430
Total accrued liabilities	$ 23,293	$ 17,930

Other Assets (long-term). The major categories are presented in the following table (in thousands):

	March 31, 2018	December 31, 2017
Escrow deposit - Apache lawsuit	$ 49,500	$ 49,500
Appeal bond deposits	6,925	6,925
Investment in White Cap, LLC	2,593	2,511
Unamortized brokerage fee for Monza	1,724	—
Proportional consolidation of Monza other assets (Note 4)	2,387	—
Other	1,285	1,457
Total other assets	$ 64,414	$ 60,393

Other Liabilities (long-term). The major categories are presented in the following table (in thousands):

	March 31, 2018	December 31, 2017
Apache lawsuit	$ 49,500	$ 49,500
Uncertain tax positions including interest/penalties	11,124	11,015
Other	6,369	6,351
Total other liabilities (long-term)	$ 66,993	$ 66,866

Recent Accounting Developments. In February 2016, the FASB issued Accounting Standards Update No. 2016-02 ("ASU 2016-02"), *Leases* (*Subtopic 842*). Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Consistent with current GAAP, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a financing or operating lease. However, unlike current GAAP, which requires only capital or financing leases to be recognized on the balance sheet, ASU 2016-02 will require both types of leases to be recognized on the balance sheet. ASU 2016-02 also will require disclosures to help investors and other financial statement users to better understand the amount, timing and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative requirements, providing additional information about the amounts recorded in the financial statements. ASU 2016-02 does not apply for leases for oil and gas properties, but does apply to equipment used to explore and develop oil and gas resources. ASU 2016-02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective approach. Our current operating leases that will be impacted by ASU 2016-02 are leases for office space, which is primarily in Houston, Texas, although ASU 2016-02 may impact the accounting for leases related to equipment depending on the term of the lease. We currently do not have any leases classified as financing leases nor do we have any leases recorded on the Condensed Consolidated Balance Sheets. We have not yet fully determined or quantified the effect ASU 2016-02 will have on our financial statements.

In June 2016, the FASB issued Accounting Standards Update No. 2016-13, ("ASU 2016-13"), *Financial Instruments – Credit Losses* (*Subtopic 326*). The new guidance eliminates the probable recognition threshold and broadens the information to consider past events, current conditions and forecasted information in estimating credit losses. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019 and early adoption is permitted for fiscal years beginning after December 15, 2018. We have not yet fully determined or quantified the effect ASU 2016-13 will have on our financial statements.

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

2. Long-Term Debt

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

	March 31, 2018			December 31, 2017		
	Principal	Adjustments to Carrying Value (1)	Carrying Value	Principal	Adjustments to Carrying Value (1)	Carrying Value
11.00% 1.5 Lien Term Loan, due November 2019:						
Principal	$ 75,000	$ —	$ 75,000	$ 75,000	$ —	$ 75,000
Future interest payments	—	13,539	13,539	—	15,596	15,596
Subtotal	75,000	13,539	88,539	75,000	15,596	90,596
9.00 % Second Lien Term Loan, due May 2020:	300,000	—	300,000	300,000	—	300,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020:						
Principal	171,769	—	171,769	171,769	—	171,769
Future payments-in-kind	—	5,745	5,745	—	5,745	5,745
Future interest payments	—	34,872	34,872	—	34,872	34,872
Subtotal	171,769	40,617	212,386	171,769	40,617	212,386
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021:						
Principal	153,192	—	153,192	153,192	—	153,192
Future payments-in-kind	—	11,323	11,323	—	11,323	11,323
Future interest payments	—	38,682	38,682	—	38,682	38,682
Subtotal	153,192	50,005	203,197	153,192	50,005	203,197
8.50% Unsecured Senior Notes, due June 2019	189,829	—	189,829	189,829	—	189,829
Debt premium, discount, issuance costs, net of amortization	—	(3,612)	(3,612)	—	(3,956)	(3,956)
Total long-term debt	889,790	100,549	990,339	889,790	102,262	992,052
Current maturities of long-term debt (2)	—	22,858	22,858	—	22,925	22,925
Long term debt, less current maturities	$ 889,790	$ 77,691	$ 967,481	$ 889,790	$ 79,337	$ 969,127

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

Accounting for Certain Debt Instruments

We accounted for a transaction executed on September 7, 2016 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 9.00/ 10.75% Second Lien PIK Toggle Notes, due May 15, 2020, (the "Second Lien PIK Toggle Notes"); the Third Lien PIK Toggle Notes and 1.5 Lien Term Loan (the "New Debt") are measured using all future undiscounted payments (principal and interest); therefore, no interest expense has been recorded for the New Debt in the Condensed Consolidated Statements of Operations for the periods presented. Additionally, no interest expense related to the New Debt will be recorded in future periods as payments of interest on the New Debt will be recorded as a reduction in the carrying amount; thus, our reported interest expense will be significantly less than the contractual interest payments through the terms of the New Debt. Under ASC 470-60, payments related to the New Debt are reported in the financing section of the Condensed Consolidated Statements of Cash Flows.

The primary terms of our long-term debt are described below:

Credit Agreement. The Credit Agreement provides a revolving bank credit facility and expires by its term on November 8, 2018. The primary items of the Credit Agreement are as follows, with certain terms defined under the Credit Agreement:

- The borrowing base is $150.0 million.
- Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists.
- The First Lien Leverage Ratio limit is 2.00 to 1.00.
- The Current Ratio must be greater than 1.00 to 1.00.
- We are required to have deposit accounts only with banks under the Credit Agreement with certain exceptions.
- We may not have unrestricted cash balances above $35.0 million if outstanding balances on the revolving bank credit agreement (including letters of credit) are greater than $5.0 million.
- To the extent there are borrowings, they are primarily executed as Eurodollar Loans, and the applicable margins range from 3.00% to 4.00%.
- The commitment fee is 50 basis points for all levels of utilization.

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

The Credit Agreement contains various customary covenants for certain financial tests, as defined in the Credit Agreement and are measured as of the end of each quarter, and for customary events of default. The customary events of default include: (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) bankruptcy or insolvency with respect to the Company or any of its subsidiaries guaranteeing borrowings under the revolving bank credit facility; or (iii) a change of control. The Credit Agreement contains cross-default clauses with the other long-term debt agreements, and such agreements contain similar cross-default clauses with the Credit Agreement.

As of March 31, 2018 and December 31, 2017, we did not have any borrowings outstanding on the revolving bank credit facility and had $0.3 million of letters of credit outstanding. Thus, available credit as of March 31, 2018 was $149.7 million.

1.5 Lien Term Loan. In September 2016, we entered into the 1.5 Lien Term Loan with a maturity date of November 15, 2019. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Interest accrues at 11.00% per annum and is payable quarterly in cash. The 1.5 Lien Term Loan is secured by a 1.5 priority lien on all of our assets pledged under the Credit Agreement. The lien securing the 1.5 Lien Term Loan is subordinate to the liens securing the Credit Agreement and has priority above the liens securing the Second Lien Term Loan (defined below), the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes. All future undiscounted cash flows have been included in the carrying value under ASC 470-60. The 1.5 Lien Term Loan contains various covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase the Unsecured Senior Notes at a price greater than 65% of par and limited to a basket of $35 million; (iii) repurchase our common stock; (iv) sell our assets; (v) make certain loans or investments; (vi) merge or consolidate; (vii) enter into certain liens; (viii) create liens that secure debt; and (ix) enter into transactions with affiliates.

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

Second Lien PIK Toggle Notes. In September 2016, we issued Second Lien PIK Toggle Notes with a maturity date of May 15, 2020. Interest is payable on May 15 and November 15 of each year. The Second Lien PIK Toggle Notes contain provisions whereby certain semi-annual interest is added to the principal amount through payment-in-kind instead of being paid in cash in the then current semi-annual period. For the interest period from November 15, 2017 up to and including March 6, 2018, we elected the option to pay that portion of interest in kind at the rate of 10.75% per annum. After March 7, 2018, interest is payable in cash at the rate of 9.00% per annum. The Second Lien PIK Toggle Notes are secured by a second-priority lien on all of our assets that are pledged under the Credit Agreement. The Second Lien PIK Toggle Notes are effectively subordinate to the Credit Agreement and the 1.5 Lien Term Loan and are effectively *pari passu* with the Second Lien Term Loan. The Second Lien PIK Toggle Notes contain covenants that limit or prohibit our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company.

Third Lien PIK Toggle Notes. In September 2016, we issued Third Lien PIK Toggle Notes with a maturity date of June 15, 2021. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Interest is payable on June 15 and December 15 of each year. The Third Lien PIK Toggle Notes contain interest provisions whereby certain semi-annual interest is added to the principal amount through payment-in-kind instead of being paid in cash in the then current semi-annual period. For interest periods up to and including September 6, 2018, if we so elect, we have the option to pay all or a portion of interest in kind at a rate of 10.00% per annum. After September 7, 2018, interest is payable in cash at the rate of 8.50% per annum. The Third Lien PIK Toggle Notes are secured by a third-priority lien on all of our assets that are secured under the Credit Agreement. The Third Lien PIK Toggle Notes are effectively subordinate to the Second Lien Term Loan and the Second Lien PIK Toggle Notes. The Third Lien PIK Toggle Notes contain covenants that limit or prohibit our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company.

Unsecured Senior Notes. Our outstanding Unsecured Senior Notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019, were recorded at their carrying value, which includes unamortized debt premium and unamortized debt issuance costs. Interest on the Unsecured Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the Unsecured Senior Notes is 8.4%, which includes amortization of premiums and debt issuance costs. The Unsecured Senior Notes contain covenants that limit or prohibit our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries to us; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company.

Covenants. We were in compliance with all applicable covenants for all of our debt instruments as of March 31, 2018.

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

3. Fair Value Measurements

We measure the fair value of our open derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The fair value of the 1.5 Lien Term Loan was estimated using the carrying value of the principal as only one entity has been the holder of the 1.5 Lien Term Loan. The fair values of our Second Lien Term Loan, Second Lien PIK Toggle Notes, Third Lien PIK Toggle Notes and Unsecured Senior Notes were based on quoted prices, although the market is not a very active market; therefore, the fair value is classified within Level 2.

The following table presents the fair value of our long-term debt, all of which are classified as Level 2 within the valuation hierarchy (in thousands):

	Hierarchy	March 31, 2018	December 31, 2017
11.00% 1.5 Lien Term Loan, due November 2019	Level 2	$ 75,000	$ 75,000
9.00 % Second Lien Term Loan, due May 2020	Level 2	297,000	288,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020	Level 2	164,898	162,322
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021	Level 2	127,149	119,490
8.50% Unsecured Senior Notes, due June 2019	Level 2	182,236	178,439

The long-term debt items are reported on the Condensed Consolidated Balance Sheets at their carrying value as described in Note 2.

4. JV Drilling Program

On March 12, 2018, W&T and two other initial members formed and initially funded a limited liability company, Monza, which will jointly participate with us in the exploration, drilling and development of up to 14 identified drilling projects in the Gulf of Mexico over the next three years. W&T contributed 88.94% of its working interest in the 14 identified projects to Monza and retained an 11.06% working interest. The projected cost to Monza to fully develop the 14 projects is estimated to be $298.6 million, excluding contingencies. Since the initial closing on March 12, 2018, additional investors have joined in Monza and as of April 27, 2018, total commitments by all investors are $297.6 million. We anticipate additional investors will join in the program. If we experience cost overruns on every project, which is unlikely, then the total cost of all projects could be as high as approximately $373 million, of which W&T would have an indirect (through Monza) cash commitment of approximately $37.5 million. See Note 11 for additional information. W&T will be the operator of all the drilling projects unless there is already a designated third-party operator.

One of the initial members of Monza is an entity owned and controlled by Harbourvest Partners, a Boston based private equity fund. The other initial members are 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 Harbourvest Partners 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 $13.4 million, which commitment will be increased as and when additional investors join the JV Drilling Program up to an amount not to exceed $16.8 million.

In summary, W&T owns a direct interest in the 14 drilling projects as well as an indirect interest via its interest in Monza. The JV Drilling Program is structured so that we initially receive an aggregate of 30.0% of the net revenues, 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.

At the inception of Monza, W&T received a net reimbursement of approximately $20 million for the capital expenditures incurred prior to the close date for projects in the JV Drilling Program. W&T may fund certain cost overruns, subject to certain exceptions, on JV Drilling Program wells above budgeted amounts.

We hold a variable interest in Monza, which is a variable interest entity which we account for utilizing proportional consolidation. We do not fully consolidate Monza because we are not considered the primary beneficiary. Information on the structure and relationship follows:

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

Accounting Methodology and Carrying Amounts. As we are not the primary beneficiary and we do not have control of Monza, we are utilizing proportional consolidation for our interest in Monza. As of March 31, 2018 in the Condensed Consolidated Statement of Financial Position, we recorded $2.4 million in prepaid assets, $44.9 million in oil and natural gas properties, $2.4 million in other assets and $1.0 million in accounts payable in connection with our proportional interest in Monza's assets and liabilities.

Maximum Exposure. Our maximum exposure within Monza as of March 31, 2018 is $48.7 million, which consists of $6.7 million cash contributed to Monza and $42.0 million of fair value for the conveyance of the 88.94% of the Company's working interest in the 14 projects. We may also take responsibility for certain drilling and completion cost overruns, subject to certain limitations and certain exceptions.

5. Asset Retirement Obligations

Our ARO primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives.

A summary of the changes to our ARO is as follows (in thousands):

Balance, December 31, 2017	$	300,446
Liabilities settled		(7,022)
Accretion of discount		4,536
Disposition of properties		(297)
Revisions of estimated liabilities (1)		8,820
Balance, March 31, 2018		306,483
Less current portion		25,748
Long-term	$	280,735

(1) Revisions were primarily related to wells that experienced sustained casing pressure issues.

6. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and, from time to time, we use various derivative instruments to manage our exposure to this commodity price risk from sales of our oil and natural gas. All of the derivative counterparties are also lenders or affiliates of lenders participating in our revolving bank credit facility. We are exposed to credit loss in the event of nonperformance by the derivative counterparties; however, we currently anticipate that each of our derivative counterparties will be able to fulfill their contractual obligations. Additional collateral is not required by us due to the derivative counterparties' collateral rights as lenders, and we do not require collateral from our derivative counterparties.

We have elected not to designate our commodity derivative contracts as hedging instruments; therefore, all changes in the fair value of derivative contracts were recognized currently in earnings during the periods presented. The cash flows of all of our commodity derivative contracts are included in *Net cash provided by operating activities* on the Condensed Consolidated Statements of Cash Flows.

As of March 31, 2018, we did not have any open commodity derivative contracts and did not enter into any derivative contracts during the three months ended March 31, 2018. During the three months ended March 31, 2017, we entered into commodity contracts for crude oil and natural gas and did not have any open commodity derivative contracts as of December 31, 2017.

7. Share-Based Compensation and Cash-Based Incentive Compensation

Awards to Employees. In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our shareholders, and amendments to the Plan were approved by our shareholders in May 2013, May 2016 and May 2017. The May 2017 amendment increased the number of shares available in the Plan by 7,700,000 shares. As allowed by the Plan, during 2017 and 2016, the Company granted restricted stock units ("RSUs") to certain of its employees. RSUs are a long-term compensation component of the Plan, which are granted to certain employees, and are subject to adjustments at the end of the applicable performance period based on the results of certain predetermined criteria. In addition to share-based compensation, the Company may grant to its employees cash-based incentive awards, which are a short-term component of the Plan and are typically based on the Company and the employee achieving certain pre-defined performance criteria.

As of March 31, 2018, there were 13,363,792 shares of common stock available for issuance in satisfaction of awards under the Plan. The shares available for issuance are reduced when RSUs are settled in shares of common stock, net of withholding tax. The Company has the option at vesting to settle RSUs in stock or cash, or a combination of stock and cash. The Company plans to settle RSUs that vest in the future using shares of common stock.

RSUs currently outstanding related to the 2017 and 2016 grants have been adjusted for performance achieved against predetermined criteria for the applicable performance year. These RSUs continue to be subject to employment-based criteria and vesting occurs in December of the second year after the grant. See the table below for potential 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 2017 and 2016 were determined using the Company's closing price on the grant date. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that are expected to actually vest.

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

There were no grants or vesting of RSUs during the three months ended March 31, 2018. For the outstanding RSUs issued to the eligible employees as of March 31, 2018, vesting is expected to occur as follows:

	Restricted Stock Units
2018	3,743,872
2019	2,022,020
Total	5,765,892

Awards to Non-Employee Directors. Under the Director Compensation Plan, shares of restricted stock ("Restricted Shares") have been granted to the Company's non-employee directors. Grants to non-employee directors were made during 2017, 2016 and 2015. As of March 31, 2018, there were 170,524 shares of common stock available for issuance in satisfaction of awards under the Director Compensation Plan. The shares available are reduced when Restricted Shares are granted.

We recognize compensation cost for share-based payments to non-employee directors 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 Restricted Shares granted were determined using the Company's closing price on the grant date. No forfeitures were estimated for the non-employee directors' awards.

The Restricted Shares are subject to service conditions and vesting occurs at the end of specified service periods unless approved by the Board of Directors. Restricted Shares cannot be sold, transferred or disposed of during the restricted period. The holders of Restricted Shares generally have the same rights as a shareholder of the Company with respect to such Restricted Shares, including the right to vote and receive dividends or other distributions paid with respect to the Restricted Shares.

There were no grants or vesting of Restricted Shares during the three months ended March 31, 2018. For the outstanding Restricted Shares issued to the non-employee directors as of March 31, 2018, vesting is expected to occur as follows:

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

Share-Based Compensation. Share-based compensation expense is recorded in the line *General and administrative expenses* in the Condensed Consolidated Statements of Operations. A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit is as follows (in thousands):

	Three Months Ended March 31,	
	2018	2017
Share-based compensation expense from:		
Restricted stock units	$ 1,149	$ 1,858
Restricted Shares	70	70
Total	$ 1,219	$ 1,928
Share-based compensation tax benefit:		
Tax benefit computed at the statutory rate	$ 256	$ 675

Unrecognized Share-Based Compensation. As of March 31, 2018, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $5.0 million and $0.3 million, respectively. Unrecognized share-based compensation expense will be recognized through November 2019 for RSUs and April 2020 for Restricted Shares.

Cash-Based Incentive Compensation. In addition to share-based compensation, cash-based awards were granted under the Plan to substantially all eligible employees in 2017 and 2016. The cash-based awards, which are a short-term component of the Plan, are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each such criterion. In addition, these cash-based awards included an additional financial condition requiring Adjusted EBITDA less reported Interest Expense Incurred (as defined in the awards) for any fiscal quarter plus the three preceding quarters to exceed defined levels measured over defined time periods for each cash-based award. Expense is recognized over the service period once the business criteria, individual performance criteria and financial condition are met.

- For the 2017 cash-based awards, a portion of the business criteria and individual performance criteria were achieved. The financial condition requirement of Adjusted EBITDA less reported Interest Expense Incurred exceeding $200 million over four consecutive quarters was achieved; therefore, incentive compensation expense was recognized in 2017 and in the first two months of 2018 for the 2017 cash-based awards. Payments were made in March 2018.

- For the 2016 cash-based awards, the financial condition requirement of Adjusted EBITDA less reported Interest Expense Incurred exceeding $300 million over four consecutive quarters was not achieved as of March 31, 2018; therefore no expense was recognized during the three months ended March 31, 2018 or during 2017. The terms of the 2016 cash-based awards allow for the achievement of the financial condition up through December 31, 2018. If the financial condition is achieved, payment is to be made within 30 days of achievement of the financial condition.

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Share-based compensation included in:		
General and administrative expenses	$ 1,219	$ 1,928
Cash-based incentive compensation included in:		
Lease operating expense	860	—
General and administrative expenses	2,672	—
Total charged to operating income	$ 4,751	$ 1,928

8. Income Taxes

Our income tax expense for the three months ended March 31, 2018 was $0.1 million and our income tax benefit for the three months ended March 31, 2017 was $7.6 million. Our effective tax rate was not meaningful for either period presented. The income tax expense in the three months ended March 31, 2018 represents the interest on uncertain tax positions. Excluding this adjustment, tax expense would have been zero for the three months ended March 31, 2018. Our current full-year forecast for 2018 has a net operating loss for tax purposes; therefore, no current tax expense is recorded. In addition, no deferred income tax expense is recorded due to dollar-for-dollar offsets by our valuation allowance. The income tax benefit for the three months ended March 31, 2017 relates to net operating loss carryback claims made pursuant to Internal Revenue Code ("IRC") Section 172(f) (related to rules for "specified liability losses"), which permit certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years.

During the three months ended March 31, 2018 and 2017, we did not receive any income tax refunds and made no income tax payments of significance.

As of March 31, 2018, we recorded current income taxes receivable of $65.1 million. As of December 31, 2017, the balance sheet reflects current income taxes receivable of $13.0 million and non-current income taxes receivable of $52.1 million. The receivables primarily relate to a net operating loss claim carried back for 2017 and net operating loss claims for the years 2012, 2013 and 2014 that were carried back to prior years. These carryback claims are made pursuant to IRC Section 172(f) described above. The refund claims for the years 2012, 2013 and 2014 require a review by the Congressional Joint Committee on Taxation.

As of March 31, 2018 and December 31, 2017, our valuation allowance was $165.7 million and $171.5 million, respectively, related to federal and state deferred tax assets. Net deferred tax assets were recorded related to NOLs 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. Although our net deferred tax assets and the related valuation allowance reflect the provisions of the Tax Cuts and Jobs Act ("TCJA"), due to the timing and the complexity of the provisions of the TCJA, further adjustments may be required during 2018 in determination of the final effect in our financial statements.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the three months ended March 31, 2018 and 2017, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefits. For the first quarter of 2018, the amount reported as income tax expense is entirely attributable to this accrued interest.

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

9. Earnings Per Share

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Net income	$ 27,640	$ 24,299
Less portion allocated to nonvested shares	1,145	1,058
Net income allocated to common shares	$ 26,495	$ 23,241
Weighted average common shares outstanding	138,845	137,513
Basic and diluted earnings per common share	$ 0.19	$ 0.17

10. Contingencies

Apache Lawsuit. On December 15, 2014, Apache filed a lawsuit against the Company alleging that W&T breached the joint operating agreement related to, among other things, the abandonment of three deepwater wells in the Mississippi Canyon ("MC") area of the Gulf of Mexico. A trial court judgment was rendered from the U.S. District Court for the Southern District of Texas on May 31, 2017 directing the Company to pay Apache $43.2 million, plus $6.3 million in prejudgment interest, attorney's fees and costs assessed in the judgment. We filed an appeal of the trial court judgment in the U.S. Court of Appeals for the Fifth Circuit. Prior to filing the appeal, in order to stay execution of the judgment, we deposited $49.5 million with the registry of the court in June 2017.

The deposit of $49.5 million with the registry of the court is recorded in *Other assets (*long-term) on the Condensed Consolidated Balance Sheets as of March 31, 2018 and December 31, 2017. Although we are appealing the decision, based solely on the decision rendered, we have recorded $49.5 million in *Other liabilities* (long-term) as of March 31, 2018 and December 31, 2017.

Appeal with the Office of Natural Resources Revenue ("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; 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 Department of the Interior. On January 27, 2017, the IBLA affirmed the decision of the ONRR requiring W&T to pay approximately $4.7 million in additional royalties. We filed an appeal of the IBLA decision on July 25, 2017 in the U.S. District Court for the Eastern District of Louisiana. 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.

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-Q, 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. For the three months ended March 31, 2018 and 2017, we paid additional royalty payments of less than $0.1 million and $0.7 million, respectively. We are not able to determine the range of any additional royalties or, if and when assessed, whether such amounts would be material.

Notices of Proposed Civil Penalty Assessment. During the three months ended March 31, 2018 and 2017, we did not pay any civil penalties to the Bureau of Safety and Environmental Enforcement ("BSEE") related to Incidents of Noncompliance ("INCs") at various offshore locations. We currently have five open civil penalties issued by the BSEE from INCs, which have not been settled as of the filing date of this Form 10-Q. The INC's underlying the civil penalties relate to separate offshore locations with occurrence dates ranging from July 2012 to June 2014. The proposed civil penalties for these INCs total $7.8 million. We have accrued approximately $3.3 million as of March 31, 2018, 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.

Surety Bond Collateral. The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for plugging and abandonment activities. We may be required to post collateral at any time pursuant to the terms of our agreement with various sureties under our existing bonds, if they so demand at their discretion. We did not receive any collateral demands from surety bond providers during the three months ended March 31, 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.

11. Subsequent Events

Heidelberg Field Acquisition. On April 5, 2018, we closed on the acquisition in the Heidelberg field whereby we acquired a 9.375% non-operated, working interest in Green Canyon blocks 859, 903 and 904. The gross purchase price was $31.1 million which was adjusted for certain closing items and an effective date of January 1, 2018. Cash flows generated by the acquired interest between the effective date and the closing date will serve to reduce the final purchase price. The acquisition required the issuance of a letter of credit of $9.4 million to a pipeline company as consignee and which issuance required a cash deposit of approximately $4.7 million with the lead bank under our Credit Agreement (representing the amount of letters of credit in excess of $5.0 million). Under our Credit Agreement, letters of credit are considered borrowings and we cannot have more than $5.0 million borrowed if we have more than $35.0 million of cash on hand (anti-hoarding provision).

JV Drilling Program. Subsequent to March 31, 2018 and up to the filing date of this Form 10-Q, five additional third-party investors made commitments to the JV Drilling Program, bringing the total commitment to approximately $297.6 million. These additional investors are subject to the same terms and conditions as the original investors. These additional commitments will not change the Company’s proportional interest in Monza, as additional contributions will be made by the Company to maintain its current percentage.

12. Supplemental Guarantor Information

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

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

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

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

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

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

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

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of the Parent Company and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. As a result of the JV Drilling Program, we recorded proportional consolidation adjustments, which are not considered a guarantor asset under our debt agreements and, accordingly, are reported as non-guarantor adjustments in the following tables. Due to the methodology of recording the ceiling-test write down in prior periods, consolidating adjustments are required to present the consolidated results appropriately.

Condensed Consolidating Balance Sheet as of March 31, 2018

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Adjustments	Eliminations	Consolidated W&T Offshore, Inc.
			(In thousands)		
Assets					
Current assets:					
Cash and cash equivalents	$ 130,711	$ —	$ —	$ —	$ 130,711
Receivables:					
Oil and natural gas sales	3,842	41,100	—	—	44,942
Joint interest	17,835	—	—	—	17,835
Income taxes	186,134	—	—	(121,031)	65,103
Total receivables	207,811	41,100	—	(121,031)	127,880
Prepaid expenses and other assets	14,592	3,206	2,399	—	20,197
Total current assets	353,114	44,306	2,399	(121,031)	278,788
Oil and natural gas properties and other, net	406,308	128,745	44,947	(6,648)	573,352
Restricted deposits for asset retirement obligations	25,622	—	—	—	25,622
Other assets	577,871	503,839	(46,378)	(970,918)	64,414
Total assets	$ 1,362,915	$ 676,890	$ 968	$ (1,098,597)	$ 942,176
Liabilities and Shareholders' Equity (Deficit)					
Current liabilities:					
Accounts payable	$ 70,997	$ 5,477	$ 970	$ —	$ 77,444
Undistributed oil and natural gas proceeds	20,598	1,675	—	—	22,273
Asset retirement obligations	23,635	2,113	—	—	25,748
Long-term debt	22,858	—	—	—	22,858
Accrued liabilities	23,437	120,887	—	(121,031)	23,293
Total current liabilities	161,525	130,152	970	(121,031)	171,616
Long-term debt:					
Principal	889,790	—	—	—	889,790
Carrying value adjustments	77,691	—	—	—	77,691
Long term debt, less current portion - carrying value	967,481	—	—	—	967,481
Asset retirement obligations, less current portion	154,861	125,862	12	—	280,735
Other liabilities	617,034	—	—	(550,041)	66,993
Shareholders' deficit:					
Common stock	1	—	—	—	1
Additional paid-in capital	547,039	704,885	—	(704,885)	547,039
Retained earnings (deficit)	(1,060,859)	(284,009)	(14)	277,360	(1,067,522)
Treasury stock, at cost	(24,167)	—	—	—	(24,167)
Total shareholders' equity (deficit)	(537,986)	420,876	(14)	(427,525)	(544,649)
Total liabilities and shareholders' equity (deficit)	$ 1,362,915	$ 676,890	$ 968	$ (1,098,597)	$ 942,176

Condensed Consolidating Balance Sheet as of December 31, 2017

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

Condensed Consolidating Statement of Operations for the Three Months Ended March 31, 2018

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Adjustments	Eliminations	Consolidated W&T Offshore, Inc.
			(In thousands)		
Revenues	$ 63,786	$ 70,427	$ —	$ —	$ 134,213
Operating costs and expenses:					
Lease operating expenses	19,760	17,083	—	—	36,843
Production taxes	455	—	—	—	455
Gathering and transportation	2,703	2,354	—	—	5,057
Depreciation, depletion, amortization and accretion	19,420	15,814	—	2,847	38,081
General and administrative expenses	7,203	7,824	11	—	15,038
Total costs and expenses	49,541	43,075	11	2,847	95,474
Operating income	14,245	27,352	(11)	(2,847)	38,739
Earnings of affiliates	22,167	—	—	(22,167)	—
Interest expense incurred	11,323	—	—	—	11,323
Other (income) expense, net	(336)	—	3	—	(333)
Income before income tax expense (benefit)	25,425	27,352	(14)	(25,014)	27,749
Income tax expense (benefit)	(5,076)	5,185	—	—	109
Net income	$ 30,501	$ 22,167	$ (14)	$ (25,014)	$ 27,640

Condensed Consolidating Statement of Operations for the Three Months Ended March 31, 2017

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 53,707	$ 70,686	$ —	$ 124,393
Operating costs and expenses:				
Lease operating expenses	23,702	16,462	—	40,164
Production taxes	515	—	—	515
Gathering and transportation	2,566	3,643	—	6,209
Depreciation, depletion, amortization and accretion	19,154	20,105	731	39,990
General and administrative expenses	5,776	7,498	—	13,274
Derivative gain	(3,955)	—	—	(3,955)
Total costs and expenses	47,758	47,708	731	96,197
Operating income	5,949	22,978	(731)	28,196
Earnings of affiliates	17,527	—	(17,527)	—
Interest expense incurred	11,294	—	—	11,294
Other expense, net	191	—	—	191
Income before income tax expense (benefit)	11,991	22,978	(18,258)	16,711
Income tax expense (benefit)	(13,039)	5,451	—	(7,588)
Net income	$ 25,030	$ 17,527	$ (18,258)	$ 24,299

Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2018

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Adjustments	Eliminations	Consolidated W&T Offshore, Inc.
			(In thousands)		
Operating activities:					
Net income	$ 30,501	$ 22,167	$ (14)	$ (25,014)	$ 27,640
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion, amortization and accretion	19,420	15,814	—	2,847	38,081
Amortization of debt items	466	—	—	—	466
Share-based compensation	1,219	—	—	—	1,219
Deferred income taxes	109	—	—	—	109
Earnings of affiliates	(22,167)	—	—	22,167	—
Changes in operating assets and liabilities:				—	
Oil and natural gas receivables	1,823	(1,322)	—	—	501
Joint interest receivables	1,919	—	—	—	1,919
Income taxes	(5,186)	5,186	—	—	—
Prepaid expenses and other assets	25,275	(31,783)	1,991	(1,874)	(6,391)
Asset retirement obligation settlements	(5,633)	(1,389)	—	—	(7,022)
Cash advances from JV partners	13,129	6,018	—	—	19,147
Accounts payable, accrued liabilities and other	2,403	(4,965)	-	1,874	(688)
Net cash provided by operating activities	63,278	9,726	1,977	—	74,981
Investing activities:					
Investment in oil and natural gas properties and equipment	(10,674)	(7,496)	(2,947)	—	(21,117)
Changes in operating assets and liabilities associated with investing activities	(15,894)	(2,230)	970	—	(17,154)
Deposit for acquisition	(3,000)	—	—	—	(3,000)
Net cash used in investing activities	(29,568)	(9,726)	(1,977)	—	(41,271)
Financing activities:					
Payment of interest on 1.5 Lien Term Loan	(2,057)	—	—	—	(2,057)
Net cash used in financing activities	(2,057)	—	—	—	(2,057)
Increase in cash and cash equivalents	31,653	—	—	—	31,653
Cash and cash equivalents, beginning of period	99,058	—	—	—	99,058
Cash and cash equivalents, end of period	$ 130,711	$ —	$ —	$ —	$ 130,711

Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2017

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 25,030	$ 17,527	$ (18,258)	$ 24,299
Adjustments to reconcile net loss to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	19,154	20,105	731	39,990
Amortization of debt items	412	—	—	412
Share-based compensation	1,928	—	—	1,928
Derivative gain	(3,955)	—	—	(3,955)
Cash receipts on derivative settlements	713	—	—	713
Deferred income taxes	105	—	—	105
Earnings of affiliates	(17,527)	—	17,527	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(2,004)	122	—	(1,882)
Joint interest receivables	5,042	—	—	5,042
Insurance reimbursements	30,100	—	—	30,100
Income taxes	(5,451)	5,451	—	—
Prepaid expenses and other assets	(6,927)	(42,395)	41,350	(7,972)
Asset retirement obligations	(12,940)	(1,559)	—	(14,499)
Cash advances from JV partners	(2,531)	—	—	(2,531)
Accounts payable, accrued liabilities and other	49,295	1,488	(41,350)	9,433
Net cash provided by operating activities	80,444	739	—	81,183
Investing activities:				
Investment in oil and natural gas properties and equipment	(23,593)	255	—	(23,338)
Changes in operating assets and liabilities associated with investing activities	2,162	(994)	—	1,168
Purchases of furniture, fixtures and other	(853)	—	—	(853)
Net cash used in investing activities	(22,284)	(739)	—	(23,023)
Financing activities:				
Payment of interest on 1.5 Lien Term Loan	(2,056)	—	—	(2,056)
Other	(245)	—	—	(245)
Net cash provided by financing activities	(2,301)	—	—	(2,301)
Increase in cash, cash equivalents and restricted cash	55,859	—	—	55,859
Cash and cash equivalents, beginning of period	70,236	—	—	70,236
Cash and cash equivalents, end of period	$ 126,095	$ —	$ —	$ 126,095

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

The following discussion and analysis should be read in conjunction with our accompanying unaudited condensed consolidated financial statements and the notes to those financial statements included in Item 1 of this Quarterly Report on Form 10-Q. The following discussion 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 (the "Exchange Act"). 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 in 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 our Annual Report on Form 10-K for the year ended December 31, 2017 and may be discussed or updated from time to time in subsequent reports filed with the 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 the context requires otherwise, references in this Quarterly Report on Form 10-Q to "W&T," "we," "us," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries and references to "Parent Company" are solely to W&T Offshore, Inc.

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 approximately 49 offshore producing fields in federal and state waters (47 producing and two fields capable of producing). We currently have under lease approximately 700,000 gross acres, with approximately 470,000 gross acres on the shelf and approximately 230,000 gross acres in the deepwater (water depths in excess of 500 feet). A majority of our daily production is derived from wells we operate. Our interest in fields, leases, structures and equipment are primarily owned by the parent company, W&T Offshore, Inc., and our wholly-owned subsidiary, W & T Energy VI, LLC, and by Monza, which we proportionately consolidate in our condensed consolidated financial statements.

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 the three months ended March 31, 2018 were comprised of 46.8% oil and condensate, 10.5% NGLs and 42.7% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel of equivalent ("Boe") for oil, NGLs and natural gas has differed significantly in the past. For the three months ended March 31, 2018, revenues from the sale of oil and NGLs made up 79.7% of our total revenues compared to 75.3% for the three months ended March 31, 2017. For the three months ended March 31, 2018, our combined total production expressed in equivalent volumes were 13.4% lower than for the three months ended March 31, 2017, with natural gas having the largest decline. For the three months ended March 31, 2018, our total revenues were 7.9% higher than the three months ended March 31, 2017 due primarily to significantly higher realized prices for oil and NGLs. See *Results of Operations – Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017* in this Item for additional information.

On March 12, 2018, W&T and two initial members formed and initially funded a limited liability company, Monza, that will jointly participate with us in the exploration, drilling and development of up to 14 identified drilling projects in the Gulf of Mexico over the next three years. W&T contributed 88.94% of its working interest in the 14 identified projects to Monza and retained an 11.06% working interest. Since the initial closing, additional investors have joined in Monza and as of April 27, 2018, total commitments by all investors are $297.6 million. We anticipate additional investors will join in the program.

In summary, W&T owns a direct interest in the 14 drilling projects as well as an indirect interest via its interest in Monza. The JV Drilling Program is structured so that we initially receive an aggregate of 30.0% of the net revenues, 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. See *Financial Statements – Note 4 –JV Drilling Program and – Note 11 –Subsequent Events* under Part I, Item 1 of this Form 10-Q for additional information

On April 5, 2018, we closed on the acquisition in the Heidelberg field whereby we acquired a 9.375% non-operated, working interest in Green Canyon blocks 859, 903 and 904. The gross purchase price was $31.1 million which was adjusted for certain closing items and an effective date of January 1, 2018. Cash flows generated by the acquired interest between the effective date and the closing date will serve to reduce the final purchase price. The acquisition required the issuance of a letter of credit of $9.4 million to a pipeline company as consignee and which issuance required a cash deposit of approximately $4.7 million with the lead bank under our Credit Agreement (representing the amount of letters of credit in excess of $5.0 million). Under our Credit Agreement, letters of credit are considered borrowings and we cannot have more than $5.0 million borrowed if we have more than $35.0 million of cash on hand (anti-hoarding provision).

Our operating results are strongly influenced by the price of the commodities that we produce and sell. The price of those commodities is affected by both domestic and international factors, including domestic production. During the three months ended March 31, 2018, our average realized oil price was $62.52 per barrel. This is an increase over our average realized oil price of $47.06 per barrel for the three months ended March 31, 2017 and an increase over our average realized oil price of $48.13 per barrel for the year 2017. In addition, average realized prices of NGLs and natural gas for the three months ended March 31, 2018 were higher than average realized prices for the three months ended March 31, 2017 and the year 2017.

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

The overall crude oil and other petroleum liquids market for the three months ended March 31, 2018 continued to have inventory draws as experienced during 2017. This trend is expected by the U.S. Energy Information Administration (“EIA”) to reverse to inventory builds for each of the remaining quarters during 2018 resulting in production and consumption to be relatively in balance for the year 2018. Crude oil prices for West Texas Intermediate (“WTI”) ranged from $59.00 per barrel to $66.00 per barrel during the three months ended March 31, 2018.

The EIA reported worldwide total crude oil and petroleum liquids inventory decreased in the first quarter of 2018 by 0.8 million barrels per day, which was a larger inventory draw than any of the inventory draws in each of the quarters for 2017. Although inventory levels have decreased from the all-time high levels in 2016, inventories at March 2018 were 1% above the five-year average and 4% above the 10-year average. Per EIA, for the remaining quarters of 2018, crude oil and petroleum liquids inventories are expected to build, ranging from 0.3 million barrels per day to 0.7 million barrels per day due to increased production.

The expected increases in production for the remainder of 2018 compared to the first quarter of 2018 are primary in the U.S., Canada and Brazil. For the year 2018, the EIA estimates worldwide crude oil and petroleum liquids production to be 100.5 million barrels per day for 2018, an increase of 2.6% over 2017. Consumption for 2018 is estimated to be 100.3 million barrels per day, an increase of 1.8% over 2017, with China and other Asian countries being the primary contributors to the increase in consumption.

According to EIA, 2018 U.S. crude oil production (excluding other petroleum liquids) is expected to increase by 17% over 2017. If EIA’s forecast is achieved in 2018, oil production in the U.S will be at the highest level in recorded history, surpassing the current record set in 1970. Net imports of crude oil in the U.S. are expected to decrease by 11% in 2018 compared to 2017. As noted below, the number of onshore rigs drilling for oil has increased from 2017 levels.

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

During the three months ended March 31, 2018, our average realized oil sales price was $62.52 per barrel, up from $47.06 per barrel (32.9% higher) for the three months ended March 31, 2017. The two primary benchmarks are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $62.91 per barrel for the three months ended March 31, 2018, up from $51.62 per barrel (21.9% higher) for the three months ended March 31, 2017. Brent crude oil prices averaged $66.86 per barrel for the three months ended March 31, 2018, up from $53.59 per barrel (24.8% higher) for the three months ended March 31, 2017. The reductions in international crude oil supply and rising U.S. crude oil production put upward price pressure on the Brent-to-WTI premium, which increased in the three months ended March 31, 2018 compared to the three months ended March 31, 2017.

Our average realized oil sales price ($62.52 per barrel compared to a WTI benchmark price of $62.91 per barrel) for the three months ended March 31, 2018 differs from the benchmark crude prices due to premiums or discounts (referred to as differentials), crude quality adjustments, volume weighting and other factors. All of our oil was produced offshore in the Gulf of Mexico and is characterized as Poseidon, Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS") and others. WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. Similar to crude oil prices, the differentials for our offshore crude oil have also experienced volatility in the past. The monthly average differentials of WTI versus Poseidon, LLS and HLS for the three months ended March 31, 2018 were a positive $0.41, a positive $4.12 and a positive $3.90 per barrel, respectively, compared to a negative $3.04, a positive $1.58 and a positive $1.02 per barrel, respectively, for the three months ended March 31, 2017.

Despite the projected build in crude oil inventory by EIA for the second quarter 2018 through the fourth quarter of 2018, it still projects average crude oil prices for both WTI and Brent to increase by approximately $9.00 per barrel for the year 2018 compared to 2017. EIA's forecast of crude oil prices for both WTI and Brent are expected to decrease by less than $1.00 per barrel for the year 2019 compared to 2018. Per EIA, economic and political instability in Venezuela continues to affect its crude oil production, which is estimated to have decreased 24% in March 2018 from year-ago levels. In addition, whether or not the U. S. will extend the Joint Comprehensive Plan of Action on Iran's nuclear program remains uncertain and without an extension, it could lead to reinstitution of sanctions on Iran affecting its production and exports.

During the three months ended March 31, 2018, our average realized NGLs sales price increased 18.0% compared to the three months ended March 31, 2017. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the three months ended March 31, 2018, average prices for domestic ethane increased 6% and average domestic propane prices increased 18% from the three months ended March 31, 2017. Average price changes for other domestic NGLs were a decrease of 4% to an increase of 28% between the two periods. We believe the increase in prices for NGLs is mostly a function of the change in oil prices and usage during the recent winter season. Per EIA, production of ethane is expected to increase 21% for 2018 compared to 2017 and propane production is expected to increase by 12% for 2018 compared to 2017. Ethane inventories increased 3% in the first quarter of 2018 compared to the same period in 2017. Ethane usage is not impacted by weather, but primarily by demand from petrochemical plants. Ethane production in 2018 and 2019 is forecast to increase year-over-year leading to further inventory builds or the re-injection of ethane back into the natural gas stream. Two new ethane steam crackers came on line in 2017 and five more are expected to be operational by the end of 2018. Propane usage is affected by weather as it is used for house heating fuel in certain areas and for crop drying, along with other uses. Propane inventory levels are 17% lower at the end of the first quarter of 2018 compared to the same period last year as heating degree days were 13% higher in the first quarter of 2018 compared to the prior year period.

During the three months ended March 31, 2018, our average realized natural gas sales price increased 1.7 % compared to the three months ended March 31, 2017. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 2.4% lower in the three months ended March 31, 2018 compared to the three months ended March 31, 2017. Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. Natural gas inventories at the end of the first quarter of 2018 were 33% lower than the prior year period and were 19% below the five-year average for the comparable periods.

Despite good demand for natural gas, the average price of natural gascontinues to be weak from an overall economic standpoint, and we expect continued weakness in natural gas prices for a number of reasons, including (i) producers continuing to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas continuing to be produced as a by-product of oil drilling, (iii) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling, pad drilling and production techniques and (iv) re-injecting ethane into the natural gas stream, which increases the natural gas supply.

EIA projects natural gas prices to be flat in 2018 compared to 2017 and to increase 3% in 2019 compared to 2018. U.S. supply is projected to be slightly higher than consumption in 2018 and 2019, resulting in minor inventory builds. EIA's forecast of fuel used for electrical power generation has natural gas increasing in 2018 to 34% from 32% in 2017. Electrical power generation from coal is forecast to decrease to 29% in 2018 from 30% in 2017. Electrical power from renewable sources such as hydropower and wind is expected to be 17% in both 2018 and 2017.

As of March 31, 2018, the number of working rigs drilling for oil and natural gas in the U.S. was significantly higher than year ago levels for land based rigs, but lower by 10 rigs working in offshore waters. According to Baker Hughes, the oil rig count at the ends of March 2018, December 2017 and March 2017 was 797, 747 and 662, respectively. The U.S. natural gas rig count at the ends of March 2018, December 2017 and March 2017 was 194, 182 and 160, respectively. In the Gulf of Mexico, the number of working rigs was 12 rigs (all oil) at March 29, 2018; 18 rigs (14 oil and four natural gas) at December 29, 2017; and 22 rigs (21 oil and one natural gas) at March 31, 2017. The majority of working rigs in the Gulf of Mexico are currently "floaters" with few jack-up rigs working.

As a result of establishing the JV Drilling Program with private investors, we have revised our 2018 capital expenditure program to $75.0 million from $130.0 million. Our 2018 capital expenditure program now includes participation in 11 wells, seven of which are included in the 2018 JV Drilling Program.

We expect to be able to address the upcoming maturities of our debt instruments, have adequate cash balances and have no draws on our revolving bank credit facility during 2018. See the *Liquidity and Capital Resources* section of this Item 2 for a discussion of our financing plans. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments.

Our short term focus is on liquidity, cost reductions, fulfilling our obligations and making investments with short payback time frames. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans. See our Annual Report on Form 10-K for the year ended December 31, 2017, Item 1A, *Risk Factors,* for additional information.

Results of Operations

The following tables set forth selected financial and operating data for the periods indicated (all values are net to our interest unless indicated otherwise):

	Three Months Ended March 31,			
	2018	2017	Change	%
	(In thousands, except percentages and per share data)			
Financial:				
Revenues:				
Oil	$ 97,306	$ 84,971	$ 12,335	14.5 %
NGLs	9,660	8,742	918	10.5 %
Natural gas	25,867	29,758	(3,891)	(13.1)%
Other	1,380	922	458	49.7 %
Total revenues	134,213	124,393	9,820	7.9 %
Operating costs and expenses:				
Lease operating expenses	36,843	40,164	(3,321)	(8.3)%
Production taxes	455	515	(60)	(11.7)%
Gathering and transportation	5,057	6,209	(1,152)	(18.6)%
Depreciation, depletion, amortization and accretion	38,081	39,990	(1,909)	(4.8)%
General and administrative expenses	15,038	13,274	1,764	13.3 %
Derivative gain	—	(3,955)	3,955	NM
Total costs and expenses	95,474	96,197	(723)	(0.8)%
Operating income	38,739	28,196	10,543	37.4 %
Interest expense	11,323	11,294	29	0.3 %
Other (income) expense, net	(333)	191	(524)	NM
Income before income tax expense (benefit)	27,749	16,711	11,038	66.1 %
Income tax expense (benefit)	109	(7,588)	7,697	NM
Net income	$ 27,640	$ 24,299	$ 3,341	13.7 %
Basic and diluted earnings per common share	$ 0.19	$ 0.17	$ 0.02	11.8 %

NM – not meaningful

	Three Months Ended March 31,			
	2018	2017	Change	% (2)
Operating: (1)				
Net sales:				
Oil (MBbls)	1,557	1,805	(248)	(13.7)%
NGLs (MBbls)	351	374	(23)	(6.1)%
Natural gas (MMcf)	8,523	9,985	(1,462)	(14.6)%
Total oil equivalent (MBoe)	3,328	3,844	(516)	(13.4)%
Total natural gas equivalents (MMcfe)	19,967	23,065	(3,098)	(13.4)%
Average daily equivalent sales (Boe/day)	36,976	42,712	(5,736)	(13.4)%
Average daily equivalent sales (Mcfe/day)	221,853	256,275	(34,422)	(13.4)%
Average realized sales prices:				
Oil ($/Bbl)	$ 62.52	$ 47.06	$ 15.46	32.9%
NGLs ($/Bbl)	27.54	23.34	4.20	18.0%
Natural gas ($/Mcf)	3.03	2.98	0.05	1.7%
Oil equivalent ($/Boe)	39.92	32.12	7.80	24.3%
Natural gas equivalent ($/Mcfe)	6.65	5.35	1.30	24.3%
Average per Boe ($/Boe):				
Lease operating expenses	$ 11.07	$ 10.45	$ 0.62	5.9%
Gathering and transportation	1.52	1.62	(0.10)	(6.2)%
Production costs	12.59	12.07	0.52	4.3%
Production taxes	0.14	0.13	0.01	7.7%
DD&A	11.44	10.40	1.04	10.0%
General and administrative expenses	4.52	3.45	1.07	31.0%
	$ 28.69	$ 26.05	$ 2.64	10.1%
Average per Mcfe ($/Mcfe):				
Lease operating expenses	$ 1.85	$ 1.74	$ 0.11	6.3%
Gathering and transportation	0.25	0.27	(0.02)	(7.4)%
Production costs	2.10	2.01	0.09	4.5%
Production taxes	0.02	0.02	—	—
DD&A	1.91	1.73	0.18	10.4%
General and administrative expenses	0.75	0.58	0.17	29.3%
	$ 4.78	$ 4.34	$ 0.44	10.1%

(1) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one Bbl 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) Variance percentages are calculated using rounded figures and may result in different figures for comparable data.

Volume measurements:

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

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Revenues. Total revenues increased $9.8 million, or 7.9%, to $134.2 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. Oil revenues increased $12.3 million, or 14.5%, NGLs revenues increased $0.9 million, or 10.5%, natural gas revenues decreased $3.9 million, or 13.1%, and other revenues increased $0.5 million. The increase in oil revenues was attributable to a 32.9% increase in the average realized sales price to $62.52 per barrel for the three months ended March 31, 2018 from $47.06 per barrel for the three months ended March 31, 2017, partially offset by a decrease in sales volumes of 13.7%. The increase in NGLs revenues was attributable to a 18.0% increase in the average realized sales price to $27.54 per barrel for the three months ended March 31, 2018 from $23.34 per barrel for the three months ended March 31, 2017, partially offset by a decrease in sales volumes of 6.1%. The decrease in natural gas revenues was attributable to a decrease in sales volumes of 1.5 billion cubic feet, or 14.6%. This was partially offset by an increase in the average realized price to $3.03 per Mcf for the three months ended March 31, 2018 from $2.98 per Mcf for the three months ended March 31, 2017. Overall, production volumes decreased 13.4% on a Boe basis. The largest production increases for the three months ended March 31, 2018 compared to the three months ended March 31, 2017 were at our Ship Shoal 299 field, our Ship Shoal 349 ("Mahogany") field and our South Timbalier 314 field. Revenue and production was adjusted for royalty relief on two of our deepwater fields related to their 2017 production and realized prices. This royalty relief was received during the first quarter of 2018, which increased revenues by $1.0 million, increased operating expenses by $0.2 million and increased production by 575 Boe per day. Offsetting were production decreases primarily due to natural production declines. Production for the three months ended March 31, 2018 was also negatively impacted by maintenance, well issues and pipeline outages that collectively resulted in deferred production of 4,200 Boe per day. During the three months ended March 31, 2017, deferred production was 1,800 Boe per day.

Revenues from oil and liquids as a percent of our total revenues were 79.7% for the three months ended March 31, 2018 compared to 75.3% for the three months ended March 31, 2017. Our average realized NGLs sales price as a percent of our average realized oil sales price decreased to 44.0% for the three months ended March 31, 2018 compared to 49.6% for the three months ended March 31, 2017.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $3.3 million, or 8.3%, to $36.8 million in the three months ended March 31, 2018 compared to the three months ended March 31, 2017. On a component basis, base lease operating expenses decreased $1.7 million, workover expenses decreased $1.5 million and facilities maintenance expense decreased $0.9 million. The decrease in lease operating expenses was partially offset by an increase in insurance premiums of $0.7 million. Base lease operating expenses decreased primarily due to lower costs at non-operated properties. The decrease in workover expense was primarily due to the 2017 period including a project at our Mahogany field that did not re-occur in 2018. The facility maintenance expense decrease is primarily attributable to compressor overhauls and pipeline projects in 2017, which did not re-occur at the same expense level during the first quarter of 2018. Insurance premium increases are primarily due to revisions in our insurance policies related to named windstorms, which had better coverage between the two periods.

Production taxes. Production taxes were basically flat for the three months ended March 31, 2018 compared to the three months ended March 31, 2017. Most of our production is from federal waters where no production taxes are imposed. Our Fairway field, which is in state waters, is subject to production taxes.

Gathering and transportation. Gathering and transportation expenses decreased $1.1 million to $5.1 million for the three months ended March 31, 2018 compared to the three months ended March 31, 2017 primarily due to lower production volumes of NGLs and natural gas.

Depreciation, depletion, amortization and accretion ("DD&A"). DD&A, which includes accretion for ARO, increased to $11.44 per Boe for the three months ended March 31, 2018 from $10.40 per Boe for the three months ended March 31, 2017. On a nominal basis, DD&A decreased to $38.1 million (4.8%) for the three months ended March 31, 2018 from $40.0 million for the three months ended March 31, 2017. DD&A on a nominal basis decreased primarily due to lower production. Other factors affecting the DD&A rate are changes in future development costs on remaining reserves and changes in proved reserves.

General and administrative expenses ("G&A"). G&A was $15.0 million for the three months ended March 31, 2018, up 13.3% from $13.3 million for the three months ended March 31, 2017. Increases in incentive compensation in 2018 were partially offset by reductions in legal costs. G&A on a per Boe basis was $4.52 per Boe for the three months ended March 31, 2018 compared to $3.45 per Boe for the three months ended March 31, 2017.

Derivative (gain) loss. We entered into derivative contracts for crude oil and natural gas during the first quarter of 2017 relating to a portion of our 2017 estimated production. The three months ended March 31, 2017 reflects a $4.0 million derivative gain primarily for our crude oil derivative contracts.

Interest expense. Interest expense was basically unchanged for three months ended March 31, 2018 and 2017. *See Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information on our debt.

Income tax expense (benefit). Our income tax expense for the three months ended March 31, 2018 was $0.1 million and our income tax benefit for the three months ended March 31, 2017 was $7.6 million. The income tax expense in the three months ended March 31, 2018 represents the interest on uncertain tax positions. Excluding this adjustment, tax expense would have been zero for the three months ended March 31, 2018. Our current full-year forecast for 2018 has a net operating loss for tax purposes; therefore, no current tax expense is recorded. In addition, no deferred income tax expense is recorded due to dollar-for-dollar offsets by our valuation allowance. Our effective tax rate using book pre-tax income was not meaningful for either period. For both periods, adjustments in the valuation allowance primarily offset changes in net deferred tax assets. See *Financial Statements – Note 8 –Income Taxes* under Part I, Item 1 of this Form 10-Q for additional information.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings, make related interest payments and satisfy our asset retirement obligations. 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 changes in regulations or the interpretation of existing regulations.

Our Credit Agreement matures on November 8, 2018. As of March 31, 2018, we had $0.3 million of letters of credit outstanding and no amounts borrowed on our revolving bank credit facility. In April 2018, we consummated the acquisition of a 9.375% non-operated working interest in the Heidelberg field, which resulted in the issuance of a letter of credit of $9.4 million and depositing $4.7 million cash under the terms of the Credit Agreement. Our Unsecured Senior Notes mature on June 15, 2019. If the Unsecured Senior Notes have not been extended, refunded, defeased, discharged, replaced or refinanced by February 28, 2019, then the 11.00% 1.5 Lien Term Loan, due November 15, 2019, and the 8.50%/10.00% Third Lien PIK Toggle Notes, due June 15, 2021, will both accelerate their maturity to February 28, 2019. During 2018, we plan to address the issues of the potential maturity acceleration of these two debt instruments and to extend or replace the revolving bank credit facility. We expect to build sufficient cash balances in 2018 to be able to redeem, repurchase or refinance the Unsecured Senior Notes. Certain amendments under the Credit Agreement and the 1.5 Lien Term Loan will likely be required in the event we redeem or repurchase the Unsecured Senior Notes, which we anticipate would be granted if requested. Assuming we can also repay or refinance the 1.5 Lien Term Loan, then we believe that we would amend our revolving bank credit facility in such a manner that will permit an extension of the maturity of such facility. There can be no assurance that lenders will extend our revolving bank credit facility maturity, but under current market conditions and based on the outlook of our cash position in 2018 and further, we believe our lenders or replacement lenders will be amenable to participating in a refinancing or corporate financing transaction.

Credit Agreement. Availability on our revolving bank credit facility as of March 31, 2018 was $149.7 million and as of April 30, 2018 was $140.3 million. Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The 2017 fall redetermination reaffirmed the borrowing base amount at $150.0 million. Any redetermination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. The revolving bank credit facility is secured and is collateralized by substantially all of our oil and natural gas properties.

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 as of March 31, 2018.

Long-Term Debt. The recorded amounts of our long-term debt and the primary terms are disclosed in *Financial Statements - Note 2 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q. We were in compliance with all applicable covenants of our long-term debt agreements as of March 31, 2018.

BOEM Matters. As of the filing date of this Form 10-Q, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to assurance obligations. During April 2018, we posted an additional $10 million of bonds as requested by BOEM to account for decommissioning obligations that accrued on sole-liability properties during the Company's period of leasing. 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.

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 materially 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. No additional demands were made to us by sureties during 2018 as of the filing date of the Form 10-Q.

The issuance of any additional surety bonds or other security to satisfy future BOEM orders, collateral requests from surety bond providers, and collateral requests from other third-parties may require the posting of cash collateral, which may be significant, and may require the creation of escrow accounts.

Cash Flow and Working Capital. Net cash provided by operating activities for the three months ended March 31, 2018 was $75.0 million compared to $81.2 million for the three months ended March 31, 2017. The change between periods is primarily due to receiving insurance reimbursements of $30.1 million during the three months ended March 31, 2017, partially offset by advances from JV partners. Our combined average realized sales price per Boe increased 24.3% in the three months ended March 31, 2018, which caused total revenues to increase $26.0 million, partially offset by decreases of 13.4% in production volumes which caused revenues to decrease by $16.6 million.

Other items affecting operating cash flows for the three months ended March 31, 2018 were ARO settlements of $7.0 million, which decreased from $14.5 million in the prior period, partially offset by changes in receivables, prepaids, other assets, accounts payable and accrued liabilities of $4.7 million.

Net cash used in investing activities during the three months ended March 31, 2018 and 2017 was $41.3 million and $23.0 million, respectively, which represents our investments in oil and gas properties and equipment. Investments in oil and natural gas properties on an accrual basis in the three months ended March 31, 2018 were $21.1 million compared to $23.3 million for the three months ended March 31, 2017. The capital expenditures during the three months ended March 31, 2018 related to investments with the majority in the conventional shelf and to a lesser extent in the deep water. In addition, adjustments from working capital changes associated with investing activities was a net cash decrease of $17.2 million in the three months ended March 31, 2018 compared to net cash increase of $1.2 million in the three months ended March 31, 2017. These amounts represent timing differences between when the work was performed and the payments are made. During the three months ended March 31, 2018, we made a deposit of $3.0 million towards the acquisition of an interest in the Heidelberg field.

Net cash used by financing activities for the three months ended March 31, 2018 was $2.1 millionand net cash used by financing activities for the three months ended March 31, 2017 was $2.3 million. The net cash used for the three months ended March 31, 2018 and 2017was primarily attributable to the interest payments on the 1.5 Lien Term Loan, 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 the three months ended March 31, 2018, we had no activity related to derivatives for crude oil and natural gas. During April 2018, we entered into several derivative contracts for crude oil with volumes totaling 11,000 barrels per day from May 2018 to December 2018.

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 limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. With respect to coverage for named windstorms, we have a $150.0 million aggregate limit covering all of our properties, subject to a retention (deductible) of $30.0 million. Included within the $150.0 million aggregate limit is total loss only (“TLO”) coverage on our Mahogany platform, which has no retention. The operational and named windstorm coverages are effective for one year beginning June 1, 2017. Coverage for pollution causing a negative environmental impact is provided under the well control and other sections within the policy.

Our general and excess liability policies are effective for one year beginning May 1, 2018 and provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE and we have insurance coverage of such amount.

Although we were able to renew our general and excess liability policies effective on May 1, 2018, and current discussions indicate we will be able to renew our Energy Package effective on June 1, 2017, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, based on recent discussion with certain insurance underwriters, we believe we will be able to renew our policies for one year with acceptable terms and pricing. We do not carry business interruption insurance.

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 oil, NGLs and natural gas, acquisition opportunities, available liquidity and the results of our exploration and development activities. During the three months ended March 31, 2018, we received reimbursement of capital expenditures from Monza for projects in the JV Drilling Program which had incurred costs during 2017. These reimbursements related to 2017 are reported in a separate line in the table below. The following table presents our capital expenditures on an accrual basis for exploration, development and other leasehold costs:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Exploration (1)	$ 1,413	$ (17)
Development (1)	29,280	22,928
Reimbursement from Monza for 2017 expenditures	(14,075)	—
Seismic, JV Drilling Program and other	4,499	427
Investments in oil and gas property/equipment	$ 21,117	$ 23,338

(1) Reported geographically in the subsequent table

The following table presents our exploration and development capital expenditures on an accrual basis geographically in the Gulf of Mexico:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Conventional shelf	$ 24,194	$ 23,367
Deepwater	6,499	(456)
Exploration and development capital expenditures	$ 30,693	$ 22,911

Our capital expenditures for the three months ended March 31, 2018 were financed by cash flow from operations and cash on hand.

During the three months ended March 31, 2018, we completed the A-17 well at Mahogany, which began producing during March 2018 and we completed the Viosco Knoll 823 (“Virgo”) A-10 ST1 well, which began production during April 2018. The Virgo A-10 ST well is in the JV Drilling Program. During the three months ended March 31, 2017, we completed two wells. We did not have any dry holes in either period.

Exploration/Development Activities. During April 2018, the rig at Virgo was relocated on the platform to drill the A-12 well. Also, in April 2018, we began drilling the Mahogany A-5 well and began drilling the South Timbalier 311 A-2 well. The Main Pass 286 #1 well has been cased and is waiting for development sanction. These four wells are in the JV Drilling Program.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. During the three months ended March 31, 2018, we did not have any property sales of significance.

Capital Expenditure Budget and Expected Production for 2018. As a result of establishing the JV Drilling Program with private investors, we have revised our 2018 capital expenditure program to $75.0 million from $130.0 million. Our 2018 capital expenditure program now includes participation in 11 wells, seven of which are included in the 2018 JV Drilling Program.

We expect to be able to address the upcoming maturities of our debt instruments, have adequate cash balances and have no draws on our revolving bank credit facility during 2018. See above for a discussion of our financing plans. We strive to maintain flexibility in our capital expenditure projects and if prices improve, we may increase our investments.

Income Taxes. As of March 31, 2018, we have recorded current income tax receivables of $65.1 million. The current income tax receivables include an estimated net operating loss claim for 2017 of $13.0 million, which is expected to be received during 2018. The other component of current income tax receivables relates to our net operating loss claims totaling $52.1 million for the years 2012, 2013 and 2014 that were carried back to prior years and are expected to be received in 2018. These receivables relate to claims made pursuant to IRC Section 172(f), (related to rules for "specified liability losses") which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. For 2018, we do not expect to make any significant income tax payments. See *Financial Statements – Note 8 –Income Taxes* under Part I, Item 1 of this Form 10-Q for additional information.

Asset Retirement Obligations. Each quarter, we review and revise our ARO estimates. Our ARO at March 31, 2018 and December 31, 2017 were $306.5 million and $300.4 million, respectively. Our plans include spending $31.6 million in 2018 for ARO compared to $72.4 million spent on ARO in 2017. As our ARO are estimates for work to be performed in the future, and in the case of our non-current ARO, are for many years in the future, actual expenditures could be substantially different than our estimates. See *Risk Factors*, under Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017 for additional information.

Contractual Obligations. Updated information on certain contractual obligations is provided in *Financial Statements – Note 2 – Long-Term Debt* and *Note 5 – Asset Retirement Obligation,* and under Part I, Item 1 of this Form 10-Q. As of March 31, 2018, drilling rig commitments, excluding ARO drilling rig commitments, were approximately $6.9 million compared to $5.7 million as of December 31, 2017. Except for scheduled utilization, other contractual obligations as of March 31, 2018 did not change materially from the disclosures in *Management's Discussion and Analysis of Financial Condition and Results of Operations,* under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2017.

Critical Accounting Policies

Our significant accounting policies are summarized in *Financial Statements and Supplementary Data* under Part II, Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2017. Also refer to *Financial Statements - Note 1 - Basis of Presentation* under Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

See *Financial Statements - Note 1 - Basis of Presentation* under Part 1, Item 1, of this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the three months ended March 31, 2018 did not change materially from the disclosures in *Quantitative and Qualitative Disclosures About Market Risk* under Part II, Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2017. As such, the information contained herein should be read in conjunction with the related disclosures in our Annual Report on Form 10-K for the year ended December 31, 2017.

Commodity Price Risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs and natural gas price declines have adversely affected our revenues, net cash provided by operating activities and profitability in the past and could have impacts on our business in the future. For the three months ended March 31, 2018, we did not have any open derivative contracts. During April 2018, we entered into derivative crude oil contracts related to a portion of our estimated production for the remainder of 2018. We historically have not designated our commodity derivatives as hedging instruments and any future derivative commodity contracts are not expected to be designated as hedging instruments. Use of these contracts may reduce the effects of volatile oil and natural gas prices, but they also may limit future income from favorable price movements.

Interest Rate Risk. As of March 31, 2018, we had no outstanding borrowings on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the London Interbank Offered Rate and the margin, which ranges from 3.00% to 4.00% depending on the amount outstanding. As of March 31, 2018, we did not have any derivative instruments related to interest rates.

Item 4. Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC and that any material information relating to us is accumulated and communicated to our management, including our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), 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 CEO and CFO, 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 CEO and CFO have each concluded that as of March 31, 2018, our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC'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 CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended March 31, 2018, there was no change in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, *Financial Statements – Note 10 – Contingencies*, of this Form 10-Q for information on various legal matters.

Item 1A. Risk Factors

Investors should carefully consider the risk factors included under Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2017, together with all of the other information included in this document, in our Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.

The potential effects of crude oil prices are discussed under Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2017 and also discussed in the Part I, Item 2, *Management's Discussion and Analysis of Financial Condition* and *Results of Operations* in the *Overview* section of this Form 10-Q.

Notwithstanding the matters discussed herein, there have been no material changes in our risk factors as previously disclosed in Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 6. 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	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))
31.1*	Section 302 Certification of Chief Executive Officer.
31.2*	Section 302 Certification of Chief Financial Officer.
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer.
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.

* Filed or Furnished herewith.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on May 3, 2018.

W&T OFFSHORE, INC.

By: /s/ JOHN D. GIBBONS
John D. Gibbons
Senior Vice President and Chief Financial Officer
(Principal Financial Officer), duly authorized to sign on behalf of the registrant

Exhibit 31.1

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

I, Tracy W. Krohn, certify that:

1. I have reviewed this quarterly report on Form 10-Q of W&T Offshore, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2018

/s/ Tracy W. Krohn

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

Exhibit 31.2

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

I, John D. Gibbons, certify that:

1. I have reviewed this quarterly report on Form 10-Q of W&T Offshore, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2018

/s/ John D. Gibbons

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

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2018 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that information contained in such Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 3, 2018

/s/ Tracy W. Krohn

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

Date: May 3, 2018

/s/ John D. Gibbons

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