W&T OFFSHORE INC
Form 10-Q
November 03, 2016

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 September 30, 2016

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company

Indicate by check mark whether the registrant is a shell company. Yes No

As of October 31, 2016, there were 137,082,824 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	September 30, 2016 (Unaudited)	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$73,351	$85,414
Receivables:		
Oil and natural gas sales	35,772	35,005
Joint interest and other	17,688	22,012
Total receivables	53,460	57,017
Prepaid expenses and other assets	16,145	26,879
Total current assets	142,956	169,310
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $0 at September 30, 2016 and $18,595 at December 31, 2015 were excluded from amortization)	7,937,338	7,902,494
Furniture, fixtures and other	20,898	20,802
Total property and equipment	7,958,236	7,923,296
Less accumulated depreciation, depletion and amortization	7,371,677	6,933,247
Net property and equipment	586,559	990,049
Deferred income taxes	12,395	27,595
Restricted deposits for asset retirement obligations	26,767	15,606
Income tax receivables	52,097	—
Other assets	11,823	5,462
Total assets	$832,597	$1,208,022
Liabilities and Shareholders' Deficit		
Current liabilities:		
Accounts payable	$83,309	$109,797
Undistributed oil and natural gas proceeds	21,239	21,439
Asset retirement obligations	90,150	84,335
Long-term debt	8,763	—
Accrued liabilities	19,573	11,922
Total current liabilities	223,034	227,493
Long-term debt, less current portion	1,014,221	1,196,855
Asset retirement obligations, less current portion	256,656	293,987
Other liabilities	16,683	16,178

Commitments and contingencies	—	—
Shareholders' deficit:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at September 30, 2016 and December 31, 2015	—	—
Common stock, $0.00001 par value; 200,000,000 shares authorized; 139,951,997 issued and 137,082,824 outstanding at September 30, 2016; 79,375,662 issued and 76,506,489 outstanding at December 31, 2015	1	1
Additional paid-in capital	537,496	423,499
Retained earnings (deficit)	(1,191,327)	(925,824)
Treasury stock, at cost; 2,869,173 shares at September 30, 2016 and December 31, 2015	(24,167)	(24,167)
Total shareholders' deficit	(677,997)	(526,491)
Total liabilities and shareholders' deficit	$832,597	$1,208,022

See Notes to Condensed Consolidated Financial Statements

1

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands except per share data) (Unaudited)			
Revenues	$107,403	$126,228	$284,773	$403,201
Operating costs and expenses:				
Lease operating expenses	37,520	45,039	118,611	143,500
Production taxes	482	889	1,378	2,526
Gathering and transportation	5,161	3,572	16,651	13,189
Depreciation, depletion, amortization and accretion	51,500	97,329	172,726	326,138
Ceiling test write-down of oil and natural gas properties	57,912	441,688	279,063	954,850
General and administrative expenses	12,692	16,515	45,370	57,038
Derivative (gain) loss	412	(10,231)	2,861	(9,153)
Total costs and expenses	165,679	594,801	636,660	1,488,088
Operating loss	(58,276)	(468,573)	(351,887)	(1,084,887)
Interest expense:				
Incurred	23,693	28,754	81,280	77,816
Capitalized	(75)	(2,203)	(520)	(6,010)
Gain on exchange of debt	123,960	—	123,960	—
Other (income) expense, net	(73)	964	1,209	2,647
Income (loss) before income tax benefit	42,139	(496,088)	(309,896)	(1,159,340)
Income tax benefit	(3,789)	(18,520)	(44,393)	(166,228)
Net income (loss)	$45,928	$(477,568)	$(265,503)	$(993,112)
Basic and diluted earnings (loss) per common share	$0.48	$(6.29)	$(3.25)	$(13.08)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' DEFICIT

	Common Stock		Additional	Retained			Total
	Outstanding		Paid-In	Earnings	Treasury Stock		Shareholders'
	Shares	Value	Capital	(Deficit)	Shares	Value	Deficit
	(In thousands)						
	(Unaudited)						
Balances at December 31, 2015	76,506	$ 1	$ 423,499	$ (925,824)	2,869	$ (24,167)	$ (526,491)
Share-based compensation	—	—	7,642	—	—	—	7,642
Stock Issued	60,577	—	106,366	—	—	—	106,366
Other	—	—	(11)	—	—	—	(11)
Net loss	—	—	—	(265,503)	—	—	(265,503)
Balances at September 30, 2016	137,083	$ 1	$ 537,496	$ (1,191,327)	2,869	$ (24,167)	$ (677,997)

See Notes to Condensed Consolidated Financial Statements.

3

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2016	2015
	(In thousands) (Unaudited)	
Operating activities:		
Net loss	$(265,503)	$(993,112)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion, amortization and accretion	172,726	326,138
Ceiling test write-down of oil and natural gas properties	279,063	954,850
Gain on exchange of debt	(123,960)	—
Debt issuance costs write-off/amortization of debt items	2,135	2,862
Share-based compensation	7,642	8,313
Derivative (gain) loss	2,861	(9,153)
Cash receipts on derivative settlements	4,746	2,139
Deferred income taxes	15,484	(166,258)
Changes in operating assets and liabilities:		
Oil and natural gas receivables	294	23,287
Joint interest and other receivables	4,281	1,210
Income taxes	(52,392)	(289)
Prepaid expenses and other assets	(16,128)	16,692
Asset retirement obligation settlements	(56,167)	(25,515)
Accounts payable, accrued liabilities and other	15,750	(6,371)
Net cash provided by (used in) operating activities	(9,168)	134,793
Investing activities:		
Investment in oil and natural gas properties and equipment	(24,062)	(192,811)
Changes in operating assets and liabilities associated with investing activities	(37,400)	(65,463)
Proceeds from sales of assets	1,500	—
Purchases of furniture, fixtures and other	(96)	(1,185)
Net cash used in investing activities	(60,058)	(259,459)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	340,000	263,000
Repayments of long-term debt - revolving bank credit facility	(340,000)	(445,000)
Issuance of Second Lien Term Loan	—	297,000
Issuance of 1.5 Lien Term Loan	75,000	—
Debt exchange/issuance costs	(17,920)	(6,591)
Other	83	54
Net cash provided by financing activities	57,163	108,463
Decrease in cash and cash equivalents	(12,063)	(16,203)
Cash and cash equivalents, beginning of period	85,414	23,666
Cash and cash equivalents, end of period	$73,351	$7,463

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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 operations offshore in the Gulf of Mexico. The Company is active in the exploration, development and acquisition of oil and natural gas properties. Our interest in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. (on a stand-alone basis, the “Parent Company”) and its 100%-owned subsidiary, W & T Energy VI, LLC (“Energy VI”). On October 15, 2015, a substantial amount of our interest in onshore acreage was sold, which is described in Note 2.

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, 2015.

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 prices of these commodities began falling in the second half of 2014, continued to generally decline in 2015, and declined further in the first nine months of 2016 on an average basis. Steps taken during 2015 and the first nine months of 2016 to mitigate the effects of these lower prices include: (i) significantly reducing the budgeted capital spending for 2015 and 2016 from historical levels; (ii) continuing the suspension of our drilling and completion activities at several locations; (iii) continued suspension of the regular quarterly common stock dividend; (iv) selling our interests in the Yellow Rose field in the fourth quarter of 2015; (v) reducing our headcount of employees and contractors; (vi) consummating the Exchange Transaction, as defined and described below; and (vii) continuing the implementation of numerous projects to reduce our operating costs. See our Annual Report on Form 10-K for the year ended December 31, 2015 concerning risks related to our business and events occurring during 2015 and other information and the Notes herein for additional information.

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million, or 79%, of our 8.500% Senior Notes due 2019 (the “Unsecured Senior Notes”) for new secured notes and common stock. At the same time, we closed on a new $75.0 million, 11.00% 1.5 Lien Term Loan (the “1.5 Lien Term Loan”), and in conjunction; two amendments were made effective under our Credit Agreement. See Note 5 for a full description of the transaction, the new debt instruments and the accounting for the transaction.

During 2015, we were notified by the BOEM that the Company was no longer eligible for any exemptions set forth in the regulations and then-current supplemental bonding procedures of the BOEM related to decommissioning obligations. In February and March 2016, we received several orders from the Bureau of Ocean Energy Management (“BOEM”) ordering the Company to provide additional security in the aggregate of $260.8 million. We filed appeals with the Interior Board of Land Appeals (“IBLA”) and the IBLA has agreed to stay the effectiveness of the orders. This is the third stay that we have received from the IBLA, and their latest stay extends the effectiveness to January 31, 2017. We submitted a proposal for a tailored plan of compliance in May 2016 under the BOEM’s then-current supplemental bonding procedures in NTL #2008-N07. Subsequently, the BOEM issued NTL #2016-N01 to replace NTL #2008-N07, effective September 2016, and we submitted a revised proposed tailored plan of compliance to the BOEM incorporating requirements of the new NTL. We continue to have discussions with the BOEM regarding these matters. See 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 liquidity to fund our operations through September 30, 2017, the period of assessment to qualify as a going concern. However, we cannot predict how an extended period of low commodity prices or the impact of future bonding requirements will affect our operations, liquidity levels and compliance with debt covenants.

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

Due primarily to declines in the unweighted rolling 12-month average of first-day-of-the-month commodity prices for oil and natural gas, we recorded ceiling test write-downs in each of the first three quarters of 2016 and in every quarter of 2015, which are reported as a separate line in the Consolidated Statements of Operations. The average price using the SEC required methodology at September 30, 2016 was $38.17 per barrel for West Texas Intermediate (“WTI”) crude oil and $2.28 per million British Thermal Unit (“MMBtu”) for Henry Hub natural gas before adjustments. Ceiling test write-downs of the carrying value of our oil and natural gas properties for the three months ended September 30, 2016 and 2015 were $57.9 million and $441.7 million, respectively, and for nine months ended September 30, 2016 and 2015 were $279.1 million and $954.9 million, respectively. The ceiling test write-down for the full year of 2015 was $987.2 million.

6

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Prepaid Expenses and Other. Amounts recorded in Prepaid expenses and other on the Condensed Consolidated Balance Sheets are expected to be realized within one year. Major categories are disclosed in the following table (in thousands):

	September 30, 2016	December 31, 2015
Derivative assets [(1)]	$ 112	$ 10,036
Prepaid/accrued insurance and surety bonds	8,334	7,475
Prepaid deposits related to royalties	5,550	5,943
Other	2,149	3,425
Prepaid expenses and other	$ 16,145	$ 26,879

(1) Includes open and closed (and not yet collected) derivative commodity contracts recorded at fair value.

Recent Accounting Developments. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), Summary and Amendments That Create Revenue from Contracts and Customers (Subtopic 606). ASU 2014-09 amends and replaces current revenue recognition requirements, including most industry-specific guidance. The revised guidance establishes a five step approach to be utilized in determining when, and if, revenue should be recognized. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. Upon application, an entity may elect one of two methods, either restatement of prior periods presented or recording a cumulative adjustment in the initial period of application. We have not fully determined or quantified the effect ASU 2014-09 will have on the recognition of our revenue, if any, nor have we determined the method we will utilize upon adoption, which would be in the first quarter of 2018.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 ("ASU 2014-15"), Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (Subtopic 205-40). The guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual and interim periods thereafter. We do not expect the revised guidance to materially affect our evaluation as to being a going concern, or have an effect on our financial statements or related disclosures.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02 ("ASU 2016-02"), Leases (Subtopic 842). Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Consistent with current GAAP, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. However, unlike current GAAP, which requires only capital leases to be recognized on the balance sheet, ASU 2016-02 will require both types of leases to be recognized on the balance sheet. ASU 2016-02 also will require disclosures to help investors and other financial statement users to better understand the amount, timing and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative requirements, providing additional information about the amounts recorded in the financial statements. ASU 2016-02 does not apply to leases for oil and gas properties, but does apply to equipment used to explore and develop oil and gas resources. Our current operating leases that will be impacted by ASU 2016-02 when it is effective are leases for office space in Houston and New Orleans, although ASU 2016-02 may impact the accounting for leases related to operations equipment depending on the term of the lease. We currently do not have any leases classified as financing leases. ASU 2016-02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective approach. We have not fully determined or quantified the effect ASU 2016-02 will have on our financial statements.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09 (“ASU 2016-09”), Compensation – Stock Compensation (Subtopic 718). The objective of ASU 2016-09 is for simplification involving several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. ASU 2016-09 is effective for annual and interim periods beginning after December 15, 2016 and early adoption is permitted. We have not yet fully determined or quantified the effect of ASU 2016-09, but do not anticipate the revised guidance will have a material effect on our financial statements.

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

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

2. Divestitures

2015 Divestiture

On October 15, 2015, we sold certain onshore oil and natural gas property interests to Ajax Resources, LLC ("Ajax") for approximately $370.9 million in cash, which includes certain customary post effective date price adjustments, and Ajax assumed responsibility for the related ARO and other associated liabilities. The effective date of the sale was January 1, 2015. A net purchase price adjustment of $0.9 million for final customary effective date adjustments was recorded during the nine months ended September 30, 2016. Ajax acquired all of our interest in the Yellow Rose field in the Permian Basin, covering approximately 25,800 net acres in Andrews, Martin, Gaines and Dawson counties in West Texas. We retained a non-expense bearing overriding royalty interest ("ORRI") equal to a variable percentage in production from the working interests assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the New York Mercantile Exchange ("NYMEX") prompt month contract trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel.

Under the full cost method, sales or abandonments of oil and natural gas properties, whether or not being amortized, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to the cost center. The sale to Ajax did not represent greater than 25% of the Company's proved reserves of oil and natural gas attributable to the full cost pool. As a result, alteration in the relationship between capitalized costs and proved reserves of oil and natural gas attributable to the full cost pool was not deemed significant and no gain or loss was recognized from the sale.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

3. 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 in accordance with applicable laws.

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

Balance, December 31, 2015	$378,322
Liabilities settled	(56,167)
Accretion of discount	13,359
Revisions of estimated liabilities [1]	11,292
Balance, September 30, 2016	346,806
Less current portion	90,150
Long-term	$256,656

(1) Revisions were primarily related to sustained casing pressure issues for idle iron at our West Cameron fields identified while performing preliminary plug and abandonment work at these fields. In addition, increases were attributable to non-operated properties. Partially offsetting are cost reduction estimates from service providers for plug and abandonment work at certain locations.

4. 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.

For information about fair value measurements, refer to Note 6.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Commodity Derivatives

As of September 30, 2016, we have open crude oil and natural gas derivative contracts for a portion of our anticipated future production for the remainder of 2016. These contracts were entered into during the second quarter of 2015. The open oil derivative contracts are known as "two-way collars" consisting of a purchased put option and a sold call option. These two-way collars provide price risk protection if crude oil prices fall below certain levels, but may limit incremental income from favorable price movements above certain limits. The oil contracts are based on WTI crude oil prices as quoted off the NYMEX. The open natural gas derivative contracts are known as "three-way collars" consisting of a purchased put option, a sold call option and a purchased call option, each at varying strike prices. The three-way collar contracts are structured to provide price risk protection if the commodity price falls below the strike price of the put option and provides us the opportunity to benefit if the commodity price rises above the strike price of the purchased call option. These contracts may have the effect of reducing some of our incremental income from favorable price movements if the commodity price is above certain levels, but have unlimited upside potential if prices rise above those levels. The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX. The strike prices of both the oil and natural gas contracts were set so that the contracts were premium neutral ("costless"), which means no net premium was paid to or received from a counterparty.

As of September 30, 2016, our open commodity derivative contracts were as follows:

Crude Oil: Two-way collars, Priced off WTI (NYMEX)

	Notional (1)	Notional (1)	Weighted Average Contract Price	
Termination Period	Quantity (Bbls/day)	Quantity (Bbls)	Put Option (Bought)	Call Option (Sold)
2016: 4th Quarter	5,000	460,000	$40.00	$81.47

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

	Notional (1)	Notional (1)	Weighted Average Contract Price		
Termination Period	Quantity (MMBTUs/day)	Quantity (MMBTUs)	Put Option (Bought)	Call Option (Sold)	Call Option (Bought)
2016: 4th Quarter (2)	40,000	2,440,000	$2.25	$3.50	$ 3.77

(1) Volume Measurements: Bbls – barrelsMMBTUs – million British Thermal Units.
(2) The natural gas derivative contracts are priced and closed in the last week prior to the related production month. Natural gas derivative contracts related to October 2016 production were priced and closed in September 2016 and are not included in the above table as these were not open derivative contracts as of September 30, 2016.

The following balance sheet line items included amounts related to the estimated fair value of our open commodity derivative contracts as indicated in the following table (in thousands):

	September 30, 2016	December 31, 2015
Prepaid and other assets	$ 112	$ 7,672
Accrued liabilities	47	—

10

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Derivative (gain) loss	$412	$(10,231)	$2,861	$(9,153)

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

	Nine Months Ended September 30,	
	2016	2015
Cash receipts on derivative settlements, net	$4,746	$2,139

Offsetting Commodity Derivatives

During 2016 and 2015, all our commodity derivative contracts permit netting of derivative gains and losses upon settlement. In general, the terms of the contracts provide for offsetting of amounts payable or receivable between us and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same commodity. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments. If we were required to settle all of our open derivative contracts, we would be able to net payments and receipts per counterparty pursuant to the derivative contracts. Although our derivative contracts allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we have historically accounted for our derivative contracts on a gross basis per contract as either an asset or liability.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

5. Long-Term Debt

Our long-term debt was as follows (in thousands):

	September 30, 2016	December 31, 2015
11.00% 1.5 Lien Term Loan, due November 2019:		
Principal	$75,000	$ —
Interest payable	26,393	—
	101,393	—
9.00 % Second Lien Term Loan, due May 2020 - Principal	300,000	300,000
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020:		
Principal	159,763	—
PIK payable	27,292	—
Interest payable	36,850	—
	223,905	—
8.50%/10.00% Third Lien PIK Toggle Notes due June 2021:		
Principal	142,031	—
PIK payable	30,711	—
Interest payable	40,705	—
	213,447	—
8.50% Unsecured Senior Notes, due June 2019 - Principal	189,829	900,000
Debt premium, discount, issuance costs, net of amortization	(5,590)	(3,145)
Total long-term debt	1,022,984	1,196,855
Current maturities of long-term debt	8,763	—
Long term debt, less current maturities	$1,014,221	$1,196,855

12

Exchange Transaction

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our Unsecured Senior Notes, due June 15, 2019 for: (i) $159.8 million in aggregate principal amount of 9.00%/10.75% Senior Second Lien PIK Toggle Notes, due May 2020, (the "Second Lien PIK Toggle Notes"); (ii) $142.0 million in aggregate principal amount of 8.50%/10.00% Senior Third Lien PIK Toggle Notes, due June 2021, (the "Third Lien PIK Toggle Notes"); and (iii) 60.4 million shares of our common stock (collectively, the "Debt Exchange"). At the same time on closing on the Debt Exchange, we closed on a $75.0 million, 11.00% 1.5 Lien Term Loan, due November 2019, with the largest holder of our Unsecured Senior Notes (collectively with the Debt Exchange, the "Exchange Transaction"). We accounted for the Exchange Transaction as a Troubled Debt Restructuring pursuant to the guidance under Accounting Standard Codification 470-60, Troubled Debt Restructuring ("ASC 470-60"). Under ASC 470-60, the carrying value of the newly issued Second Lien PIK Toggle Notes, Third Lien PIK Toggle Notes and 1.5 Lien Term Loan (the "New Debt") is measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the New Debt in the Consolidated Statements of Operations during the three and nine month months ended September 30, 2016. Additionally, no interest expense related to the New Debt will be recorded in future periods as payments of interest on the New Debt will be recorded as a reduction in the carrying amount; thus, our reported interest expense will be significantly less than the contractual interest payments through the terms of the New Debt.

A gain of $124.0 million was recognized related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as the sum of (i) the future undiscounted payments (principal and interest) related to the New Debt, (ii) the fair value of the common stock issued and (iii) deal transaction costs of $18.9 million was less than the sum of (iv) the carrying value of the Unsecured Senior Notes exchanged and (v) the funds received from the 1.5 Lien Term Loan. The shares of common stock issued were valued at $1.76 per share, which was the closing price on September 7, 2016. Transaction costs related to the Exchange Transaction of approximately $2.8 million previously recorded as General and Administrative expense were reclassified and netted against the Gain on Debt Exchange. When such costs were previously recorded, the Exchange Transaction was dependent on approvals and actions by third parties including the approval of two-thirds of our shareholders. The effect on basic and diluted earnings per share for the three and nine months ended September 30, 2016 was a $1.33 per share and $1.52 per share, respectively, which assumes the gain would not affect income tax benefit for either time period.

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

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

Credit Agreement

The Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement"), provides a revolving bank credit facility. In conjunction with the Exchange Transaction, two amendments were executed for the Credit Agreement. The primary items related to the recent amendments are:

- Borrowing base revisions have been suspended until April 2017, (referred to as a bank holiday), at which time the borrowing base will be redetermined per the normal timeframe described below. The borrowing base was not changed and remains at $150.0 million.

- The First Lien Leverage Ratio limits were changed to 2.50 to 1.00 through June 30, 2017, and to 2.00 to 1.00 thereafter.
- 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 million if outstanding balances on the revolving bank credit agreement (including letters of credit) are greater than $5 million.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

- The margins on amounts borrowed were increased. Borrowings primarily are executed as Eurodollar Loans, and the applicable margins range from 3.00% to 4.00%.
- The commitment fee was changed to 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 (commencing in 2017) and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The spring redetermination occurred in March 2016 and the next redetermination will occur in April 2017. Subsequent to April 2017, the lenders and the Company have the option for an additional redetermination every year. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base; such excess is required to be repaid within 90 days in three equal monthly payments. Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists. The revolving bank credit facility is secured and is collateralized by substantially all of our oil and natural gas properties. The Credit Agreement terminates on November 8, 2018.

The Credit Agreement contains various customary covenants for certain financial tests, as defined in the Credit Agreement and measured as of the end of each quarter, and for customary events of default. These financial test ratios and limits as of September 30, 2016 and thereafter are: (i) the First Lien Leverage Ratio must be less than 2.50 to 1.00 with a step down to 2.00 to 1.00 on September 30, 2017; (ii) the Current Ratio must be greater than 1.00 to 1.00; and (iii) the Asset Coverage Ratio must not be less than 1.25x measured on September 30, 2016 and December 31, 2016. The Asset Coverage Ratio is determined using the present value of proved reserves, discounted at 10%, and using strip forward pricing (PV-10 using strip pricing) compared to the amount of first lien debt outstanding. As of September 30, 2016, the First Lien Leverage Ratio was 0.01 to 1.00, the Current Ratio was 2.35 to 1.00 and the Asset Coverage Ratio was not meaningful, as only letters of credit were outstanding on September 30, 2016, and was well above the threshold. 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. We were in compliance with all applicable covenants of the Credit Agreement as of September 30, 2016.

We are required to have deposit accounts only with banks under the Credit Agreement with certain exceptions and may not have unrestricted cash balances above $35 million if outstanding balances on the revolving bank credit facility (including letters of credit) are greater than $5 million. We are required to maintain minimum liquidity of $15 million, defined as the sum of unrestricted cash and availability under the revolving bank credit facility.

The recent amendments increased some of the margins applied to borrowings under the revolving bank credit facility. Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate (“LIBOR”) plus a margin that varies from 3.00% to 4.00% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the greater of (a) Prime Rate, (b) Federal Funds Rate plus 0.50%, and (c) LIBOR plus 1.00%, plus applicable margin ranging from 2.00% to 3.00%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%.

The borrowing base reduction occurring in the first three months of 2016 resulted in a proportional reduction in the unamortized costs related to the Credit Agreement of $1.4 million for the nine months ended September 30, 2016, which is included in the line Other expense, net on the Condensed Statement of Operations.

The estimated annual effective interest rate was 5.6% for the nine months ended September 30, 2016 for average daily borrowings outstanding under the revolving bank credit facility. The estimated annual effective interest rate includes amortization of debt issuance costs and excludes commitment fees and other costs. As of both September 30, 2016 and December 31, 2015, we did not have any borrowings outstanding and had $0.9 million of letters of credit outstanding under the revolving bank credit facility at both dates. Availability as of September 30, 2016 was $149.1 million.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

1.5 Lien Term Loan

As part of the Exchange Transaction, we entered into the 1.5 Lien Term Loan on September 7, 2016 with a maturity date of November 15, 2019. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Interest accrues at 11.00% per annum and is payable quarterly in cash. The holder of the 1.5 Lien Term Loan was the largest holder of our Unsecured Senior Notes prior to the Exchange Transaction. The 1.5 Lien Term Loan is secured by a 1.5 priority lien on all of our assets pledged under the Credit Agreement. The lien securing the 1.5 Lien Term Loan is subordinate to the liens securing the Credit Agreement and has priority above the liens securing the Second Lien Term Loan, the Second Lien PIK Toggle Notes and the Third Lien PIK Toggle Notes. All future undiscounted cash flows have been included in the carrying value under ASC 470-60. Current maturities of long-term debt represent the cash interest payable for the 1.5 Lien Term Loan payable in the next 12 months. The 1.5 Lien Term Loan contains various covenants that limit, among other things, our ability to: (i) pay cash dividends; (ii) repurchase our common stock; (iii) sell our assets; (iv) make certain loans or investments; (v) merge or consolidate; (vi) enter into certain liens; and (vii) enter into transactions with affiliates. We were in compliance with those covenants as of September 30, 2016.

Second Lien Term Loan

At September 30, 2016 and December 31, 2015, our Second Lien Term Loan, which bears an annual interest rate of 9.00% and matures on May 15, 2020 (the “Second Lien Term Loan”), was 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 9.7%, 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 Loans (discussed above) and is effectively pari passu with the Second Lien PIK Toggle Notes (discussed below). We are subject to various covenants under the terms governing the Second Lien Term Loan including, without limitation, covenants that limit our ability to incur other debt, pay dividends or distributions on our equity, merge or consolidate with other entities and make certain investments in other entities. We were in compliance with those covenants as of September 30, 2016.

Second Lien PIK Toggle Notes

As part of the Exchange Transaction, we issued Second Lien PIK Toggle Notes on September 7, 2016, with a maturity date of May 15, 2020. Cash interest accrues at 9.00% per annum and is payable on May 15 and November 15 of each year. The Second Lien PIK Toggle Notes contain payment-in-kind (“PIK”) interest provisions, where certain semi-annual interest is added to the principal amount instead of being paid in cash in the then current semi-annual period. We have the option for the first 18 months to pay all or a portion of interest in kind at a rate of 10.75% per annum, except that the initial interest payment on November 15, 2016 is to be paid solely in kind. The Second Lien PIK Toggle Notes are secured by a second-priority lien on all of our assets that are pledged under the Credit Agreement. The Second Lien PIK Toggle Notes are effectively subordinate to the Credit Agreement and the 1.5 Lien Term Loan (discussed above) and is effectively pari passu with the Second Lien Term Loan. For purposes of determining the gain from the Exchange Transaction under ASC 470-60, we assumed the Company will elect full use of the PIK option and these amounts will increase the principal amount. All future undiscounted cash flows have been included in the carrying value under ASC 470-60. The Second Lien PIK Toggle Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with those covenants as of September 30, 2016.

Third Lien PIK Toggle Notes

As part of the Exchange Transaction, we issued Third Lien PIK Toggle Notes on September 7, 2016, with a maturity date of June 15, 2021. The maturity date will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes have not been extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Cash interest accrues at 8.50% per annum and is payable on June 15 and December 15 of each year. The Third Lien PIK Toggle Notes contain PIK interest provisions, where certain semi-annual interest is added to the principal amount instead of being paid in cash in the then current semi-annual period. We have the option for the first 24 months to pay all or a portion of interest in kind at a rate of 10.00% per annum, except that the initial interest payment on December 15, 2016 is to be paid solely in kind. The Third Lien PIK Toggle Notes are secured by a third-priority lien on all of our assets that are secured under the Credit Agreement. The Third Lien PIK Toggle Notes are effectively subordinate to the Second Lien Term Loan and the Second Lien PIK Toggle Notes. For purposes of determining the gain from the Exchange Transaction under ASC 470-60, we assumed the Company will elect full use of the PIK option and these amounts will increase the principal amount. All future undiscounted cash flows have been included in the carrying value under ASC 470-60. The Third Lien PIK Toggle Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make payments or distributions on account of our or our restricted subsidiaries' capital stock; (iii) sell assets; (iv) restrict dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. We were in compliance with those covenants as of September 30, 2016.

Unsecured Senior Notes

At September 30, 2016 and December 31, 2015, 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 consisting of principal, unamortized premium and unamortized debt issuance costs. For the Exchange Transaction, unamortized debt premium and unamortized debt issuance costs were allocated based on the principal values of the Unsecured Senior Notes exchanged and those not exchanged. The Unsecured Senior Notes are effectively subordinate to all our secured debt. 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 debt issuance costs and premiums. We are subject to various financial and other covenants under the indenture governing the Unsecured Senior Notes, and we were in compliance with those covenants as of September 30, 2016.

For information about fair value measurements for our long-term debt, refer to Note 6.

6. 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 inputs used for the fair value measurement of our derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads, credit risk and published commodity futures prices. The fair value of the 1.5 Lien Term Loan was estimated using the carrying value of the principal as no market has initially developed and the loan was recently consummated. 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 an active market; therefore, the fair value is classified within Level 2.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

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

	September 30, 2016		December 31, 2015	
	Assets	Liabilities	Assets	Liabilities
Derivatives	$112	$47	$7,672	$—
11.00% 1.5 Term Loan, due November 2019 [1]	—	75,000	—	—
9.00% Second Lien Term Loan, due May 2020 [1]	—	192,000	—	217,500
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020 [1]	—	87,870	—	—
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021 [1]	—	49,711	—	—
8.50% Unsecured Senior Notes, due June 2019 [1]	—	74,033	—	324,000

(1) The long-term debt items are reported on the Condensed Consolidated Balance Sheets at their carrying value as described in Note 5.

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 and in May 2016. The May 2016 amendment increased the number of shares available in the Plan by 3,300,000 shares. As allowed by the Plan, during 2016, 2015 and 2014, 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 only 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 September 30, 2016, there were 7,532,938 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. Although the Company has the option at vesting to settle RSUs in stock or cash, or a combination of stock and cash, only common stock has been used to settle vested RSUs to date.

RSUs currently outstanding have been adjusted for performance achieved against predetermined criteria for the applicable performance year. The RSUs outstanding continue to be subject to employment-based criteria and vesting occurs in December of the second year after the grant. See the second 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 2016, 2015 and 2014 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.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

A summary of activity in 2016 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2015	3,474,079	$ 7.42
Granted	4,209,013	2.21
Vested	(20,554)	9.87
Forfeited	(264,908)	5.11
Nonvested, September 30, 2016	7,397,630	4.53

For the outstanding RSUs issued to the eligible employees as of September 30, 2016, vesting is expected to occur as follows:

	Restricted Stock Units
2016	953,220
2017	2,340,797
2018	4,103,613
Total	7,397,630

Restricted Stock Units fair value at grant date and vested date: The fair value of Restricted Stock Units granted during the nine months ended September 30, 2016 was $9.3 million based on the Company's closing price on the date of grant. The fair value of Restricted Stock Units that vested during the nine months ended September 30, 2016 was minimal and was based on the Company's closing price on the date of vesting.

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 2016, 2015 and 2014. As of September 30, 2016, there were 317,896 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. 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.

A summary of activity in 2016 related to Restricted Shares is as follows:

	Restricted Shares	
	Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, December 31, 2015	78,230	$ 8.95
Granted	126,128	2.22
Vested	(43,062)	9.75
Nonvested, September 30, 2016	161,296	3.47

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Restricted Shares fair value at grant date and vested date: The fair value of Restricted Shares granted during the nine months ended September 30, 2016 was $0.3 million based on the Company's closing price on the date of grant. The fair value of Restricted Shares that vested during the nine months ended September 30, 2016 was $0.1 million based on the Company's closing price on the date of vesting.

For the outstanding Restricted Shares issued to the non-employee directors as of September 30, 2016, vesting is expected to occur as follows:

	Restricted Shares
2017	62,136
2018	57,120
2019	42,040
Total	161,296

Share-Based Compensation. Share-based compensation expense is recorded in the line General and administrative expenses in the Condensed 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Share-based compensation expense from:				
Restricted stock units	$2,451	$2,518	$7,339	$8,137
Restricted Shares	70	87	303	270
Common shares	—	—	—	(94)
Total	$2,521	$2,605	$7,642	$8,313
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$883	$912	$2,675	$2,910

Unrecognized Share-Based Compensation. As of September 30, 2016, unrecognized share-based compensation expense related to our awards of RSUs and Restricted Shares was $7.5 million and $0.4 million, respectively. Unrecognized share-based compensation expense will be recognized through November 2018 for RSUs and April 2019 for Restricted Shares.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees and are typically payable in cash. These awards are performance-based awards consisting of one or more business or individual performance criteria and a targeted level or levels of performance with respect to each such criterion. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

During 2016 and 2015, the Company issued cash-based incentive awards for both years that, in addition to being performance-based awards related to respective 2016 and 2015 criteria, the payment of such awards is contingent on the Company achieving the following financial condition on or before December 31, 2018 and December 31, 2017, respectively: Adjusted EBITDA less Interest Expense, as reported by the Company in its announced Earnings Release with respect to the end of any fiscal quarter plus three preceding quarters, exceeds $300.0 million. As the Company did not achieve this financial condition up through September 30, 2016, no amounts have been recognized to date related to the 2016 and 2015 cash-based incentive awards.

8. Income Taxes

Our income tax benefit for the three and nine months ended September 30, 2016 was $3.8 million and $44.4 million, respectively. Our effective tax rate for the three months ended September 30, 2016 was not meaningful primarily due to adjustments related to the book gain associated with the Exchange Transaction. The annualized effective tax rate for the nine months ended September 30, 2016 was 14.3%. Our income tax benefit for the three and nine months ended September 30, 2015 was $18.5 million and $166.2 million, respectively. The annualized effective tax rate for the three and nine months ended September 30, 2015 was 3.7% and 14.3%, respectively. Our annualized effective tax rates differs from the federal statutory rate of 35.0% for all periods presented primarily due to the valuation allowance recorded for our deferred tax assets.

During the three months and nine ended September 30, 2016, we recorded a reduction in the valuation allowance of $19.1 million and an increase in the valuation allowance of $63.1 million, respectively, related to federal and state deferred tax assets. During the three and nine months ended September 30, 2015, we recorded a valuation allowance of $156.2 million and $241.6 million, respectively. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In addition, the realization depends on the ability to carryback certain items to prior years for refunds of taxes previously paid. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As of September 30, 2016 and December 31, 2015, we had a valuation allowance related to Federal, Louisiana and Alabama net operating losses and other deferred taxes. The tax years 2012 through 2015 remain open to examination by the tax jurisdictions to which we are subject.

In connection with the Exchange Transaction, we realized a tax gain due to the concession extended by the noteholders who elected to exchange their Unsecured Senior Notes. This tax gain will be offset by a reduction in our net operating losses and other deferred tax asset attributes. The reduction in our deferred tax assets will be fully offset by a corresponding reduction in our valuation allowance.

During the third quarter, we received an income tax refund of $5.6 million primarily for a net operating loss (“NOL”) claim for 2015 carried back to 2005 filed on Form 1139, Corporation Application for Tentative Refund. In addition, we have recorded $52.1 million as non-current income tax receivables related to our NOL claims for the years 2012, 2013 and 2014 that were carried back to the years 2003, 2004, 2007, 2010 and 2011 filed on Form 1120X, U.S. Corporation Income Tax Return. These carryback claims are made pursuant to Internal Revenue Code (“IRC”) Section 172(f) which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. The refund claims filed on Form 1120X will require a review by the Congressional Joint Committee on Taxation and are accordingly classified as non-current.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the 2016 and 2015 periods reported, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

9. Earnings/ (Loss) Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income (loss)	$45,928	$(477,568)	$(265,503)	$(993,112)
Less portion allocated to nonvested shares	1,689	—	—	—
Net income (loss) allocated to common shares	$44,239	$(477,568)	$(265,503)	$(993,112)
Weighted average common shares outstanding	92,243	75,932	81,748	75,900
Basic and diluted earnings (loss) per common share	$0.48	$(6.29)	$(3.25)	$(13.08)
Shares excluded due to being anti-dilutive (weighted-average)	—	1,913	3,833	1,945

10. Equity Structure and Transactions

During September 2016, a special meeting of shareholders of common stock was held and shareholders approved two proposals, which increased the number of authorized common shares to 200,000,000 and provided for the issuance of up to 76,590,000 common shares in conjunction with the Exchange Transaction. Upon consummation of the Exchange Transaction, 60,435,544 common shares were issued to noteholders who elected to exchange their Unsecured Senior Notes.

During the nine months ended September 30, 2016 and the full year of 2015, we did not pay any dividends and a suspension of dividends remains in effect.

11. Contingencies

Supplemental Bonding Requirements by the BOEM. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances. The significant and sustained decline in crude oil and natural gas prices, however, has resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the regulations and then-current supplemental bonding procedures of the BOEM. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM under NTL #2008-N07. In February and March 2016, we received several orders from the BOEM ordering the Company to secure financial assurances in the form of additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, rights of use and easement (“RUEs”) and rights of way (“ROWs”). We have filed appeals with the IBLA regarding four of the BOEM orders - specifically the February order requiring the Company to post a total of $159.8 million in additional security and three March orders requiring $101.0 million in additional security. The IBLA, acknowledging that the BOEM and the Company were seeking to resolve the BOEM orders through settlement discussions, has agreed to stay the effectiveness of the orders. This is the third stay that we have received from the IBLA, and their latest stay extends the effectiveness to January 31, 2017. We submitted a proposal for a tailored plan of compliance in May 2016 and have had ongoing discussions with the BOEM and its sister agency, the Bureau of Safety and Environmental Enforcement (the “BSEE”), in an effort to seek an acceptable resolution of the orders.

In July 2016, effective September 12, 2016, the BOEM issued NTL #2016-N01, related to obligations for decommissioning activities on the OCS, to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional security may be required for OCS leases, ROW and RUE. This NTL supersedes and replaces NTL #2008-N07. Among other things, the NTL eliminates the "waiver exemption" currently allowed by the BOEM, whereby lessees on the OCS meeting certain financial strength and reliability criteria are exempted from posting bonds or other acceptable financial assurances for such lessee's decommissioning obligations. Under the new NTL, qualifying operators may self-insure for an amount up to 10% of their tangible net worth. In addition, the NTL implements a phase-in period for establishing compliance with additional security obligations for certain properties, whereby lessees may seek compliance with its additional security requirements under a "tailored plan" that is approved by the BOEM and would require securing phased in compliance in three approximately equal installments during a one-year period from the date of the BOEM approval of the tailored plan. Additional security for sole liability properties (those leases, ROWs or RUEs where there are no co-lessees or other grant holders or prior interest holders who may be liable to the BOEM) may not be phased in.

In July 2016, the BOEM issued an implementation timeline with respect to NTL #2016-N01, setting forth a timeline for lessees to submit a self-insurance request, for the BOEM to send out proposal letters outlining required additional security, for the BOEM to send out the order letters, for lessees to submit a tailored plan and for lessees to provide additional security. Implementation of this new NTL could result in us having to obtain additional bonds or other financial assurances and having to post collateral to obtain such additional bonds or other financial assurances.

Since the new NTL went into effect in September 2016, we have received from the BOEM "self-insurance" letters confirming that we do not qualify to self-insure a portion of any additional financial assurance, as well as "proposal" letters outlining what additional security the BOEM proposes to require from us and other parties liable for lease, ROW, and RUE decommissioning obligations. We are reviewing these proposal letters for accuracy. We have also submitted a revised proposed tailored plan of compliance to the BOEM that we believe to be consistent with a tailored arrangement under NTL #2016-N01.

Surety Bond Collateral. Some of the sureties under our existing supplemental surety bonds have requested collateral from us, and may request additional collateral from us, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety's discretion.

Notification by ONRR of Fine for Non-compliance. In December 2013 and January 2014, we were notified by the Office of Natural Resources Revenue ("ONRR") of an underpayment of royalties on certain Federal offshore oil and gas leases that cumulatively approximated $30,000 over several years, which represents 0.0045% of royalty payments paid by us during the same period of the underpayment. In March 2014, we received notice from the ONRR of a statutory fine of $2.3 million (subsequently reduced to approximately $1.1 million) relative to such underpayment. We believe the fine is excessive considering the circumstances and in relation to the amount of underpayment. On April 23, 2014, we filed a request for a hearing on the record and a general denial of the ONRR's allegations contained in the notice. We intend to contest the fine to the fullest extent possible. A hearing on this matter was held with an Administrative Law Judge in August 2016. A decision on this case has been deferred until January 2017 at the earliest. The ultimate resolution may result in a waiver of the fine, a reduction of the fine, or payment of the full amount plus interest covering several years. As no amount has been determined as more likely than any other within the range of possible resolutions, no amount has been accrued as of September 30, 2016 or December 31, 2015.

Apache Lawsuit. On December 15, 2014, Apache Corporation ("Apache") filed a lawsuit against W&T Offshore, Inc., alleging that W&T breached the joint operating agreement ("JOA" or "contract") related to the abandonment of deepwater wells in the Mississippi Canyon area of the Gulf of Mexico. That lawsuit, styled Apache Corporation v. W&T Offshore, Inc., is currently pending in the United States District Court for the Southern District of Texas. Apache contends that W&T has failed to pay its proportional share of the costs associated with plugging and abandoning three wells that are subject to the JOA. We contend that the costs incurred by Apache are excessive and unreasonable. Apache seeks an award of actual damages, interest, court costs, and attorneys' fees. In February 2015, we made a payment to Apache for our net share of the amount that we believe was reasonable to plug and abandon the wells. Our estimate of the potential exposure ranges from zero to $47.2 million (which is the amount claimed by Apache as of September 30, 2016). Such amount excludes potential interest, court costs and attorneys' fees. See Note 12 for events subsequent to September 30, 2016.

Insurance Claims. During the fourth quarter of 2012, underwriters of W&T's excess liability policies ("Excess Policies") (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company, XL Specialty Insurance Company, National Liability & Fire Insurance Company ("Starr Marine") and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas (the "District Court") seeking a determination that our Excess Policies do not cover removal-of-wreck and debris claims arising from Hurricane Ike except to the extent we have first exhausted the limits of our Energy Package (defined as certain insurance policies relating to our oil and gas properties which includes named windstorm coverage) with only removal-of-wreck and debris claims. The court consolidated the various suits filed by the underwriters. In January 2013, we filed a motion for summary judgment seeking the court's determination that such Excess Policies do not require us to exhaust the limits of our Energy Package policies with only removal-of-wreck and debris claims. In July 2013, the District Court ruled in favor of the underwriters, adopting their position that the Excess Policies cover removal-of-wreck and debris claims only to the extent the limits of our Energy Package policies have been exhausted with removal-of-wreck and debris claims. We appealed the decision in the United States Court of Appeals for the Fifth Circuit (the "Fifth Circuit") and, in June 2014, the Fifth Circuit reversed the District Court's ruling and ruled in our favor. The underwriters filed three separate briefs requesting a rehearing or a certification to the Texas Supreme Court, all of which the Court denied. A brief was subsequently filed by one underwriter requesting a rehearing to the District Court of the Fifth Circuit's decision, which the District Court denied. Claims of approximately $43 million were filed, of which approximately $1 million was paid under the Energy Package and of which approximately $1 million was paid under our Comprehensive General Liability policy. One of the underwriters, Liberty Mutual Insurance Co., paid its portion of the Excess Policies (approximately $5 million), in addition to a portion of interest owed. The other underwriters have not paid, and we filed a lawsuit in September 2014 against these underwriters for amounts owed, interest, attorney fees and damages. Subsequent to the filing of that lawsuit, Liberty Mutual Insurance Co. paid additional interest and Starr Marine has paid its portion ($5 million) of the first excess liability policy without interest. The lawsuit includes interest not paid by Starr Marine. The revised estimate of potential reimbursement is approximately $31 million, plus interest, attorney fees and damages, if any. Removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Condensed Consolidated Balance Sheets and recoveries from claims made on these Excess Policies will be recorded as reductions in this line item, which will reduce our future depreciation, depletion, amortization and accretion ("DD&A") rate.

Royalties. In 2009, the Company recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited the calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the IBLA. W&T's brief was filed in November

2014 and we expect the briefing before the IBLA to be completed in the second half of 2016.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

The ONRR has publicly announced an "unbundling" initiative to review 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. In the second quarter of 2015, pursuant to the initiative, the Company received requests from the ONRR for additional data regarding the Company's transportation and processing allowances on natural gas production that is processed through a specific processing plant. The Company also received a preliminary determination notice from the ONRR asserting its preliminary determination that the Company's allocation of certain processing costs and plant fuel use at another processing plant were impermissibly allowed as deductions in the determination of royalties owed under Federal oil and gas leases. The Company intends to submit a response to the preliminary determination asserting the reasonableness of its own allocation methodology of such costs. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under the Company's Federal oil and gas leases for current and prior periods. The Company is not able to determine the likelihood or range of any additional royalties or, if and when assessed, whether such amounts would be material.

Notices of Proposed Civil Penalty Assessment. The Company currently has five open Incidents of Noncompliance ("INCs") issued by the BSEE, which have not been settled as of the filing of this Form 10-Q. The INC's were issued during 2015 and 2016 and relate to five separate offshore locations with occurrence dates ranging from July 2012 to September 2014. The proposed civil penalties for these INCs total $8.3 million. W&T has paid one penalty in the amount of $83,000 and the contractor responsible for the activity giving rise to the penalty has agreed to reimburse W&T. The Company has accrued approximately $1.0 million, which is the Company's best estimate of the final settlement once all appeals have been exhausted. The Company's position is that the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

Iberville School Board Lawsuit. In August 2013, a citation was issued on behalf of plaintiffs, the State of Louisiana and the Iberville Parish School Board, in their suit against the Company (among others) in the 18th Judicial District Court for the Parish of Iberville, State of Louisiana. This case involves claims by the Iberville Parish School Board that this property has allegedly been contaminated or otherwise damaged by certain defendants' oil and gas exploration and production activities. The plaintiff's claims include assessment costs, restoration costs, diminution of property value, punitive damages, and attorney fees and expenses, of which were not quantified in the claim. The case was set for trial on August 15, 2016, but the trial date has been deferred until early 2017. We cannot currently estimate our potential exposure, if any, related to this lawsuit. We are currently, and intend to continue vigorously defending this litigation.

Other Claims. We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. In addition, the BOEM considers all owners of record title and/or operating rights interest in an OCS lease to be jointly and severally liable for the satisfaction of the supplemental bonding obligations and/or decommissioning obligations. Accordingly, we may be required to satisfy supplemental bonding obligations or decommissioning obligations of a defaulting owner of record title and/or operating rights interest in an OCS lease in which we are (or in some cases were) an owner of record title and/or operating rights interest in the same OCS lease. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business including matters related to alleged royalty underpayments on certain 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.

Contingent Liability Recorded. There were no material expenses recognized related to accrued and settled claims, complaints and fines for the nine months ended September 30, 2016 and 2015. As of September 30, 2016 and December 31, 2015, we had no material amounts recorded in liabilities for claims, complaints and fines.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

12. Subsequent Events

Apache Lawsuit. The case Apache Corporation v. W&T Offshore, Inc., described in Note 11, went to the jury on October 28, 2016. On the same date, the jury made the following findings:

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

W&T intends to file a motion with the trial court requesting a judgment consistent with the jury's finding that Apache acted in bad faith thereby causing W&T not to comply with the contract, which W&T asserts bars Apache from recovery for damages under applicable law, and if damages are not barred in their entirety, that any judgment for monetary damages is offset by $17.0 million as determined by the jury.

13. 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 5) 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 Sales provisions (as such terms are define in certain debt documents);

(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 Sales 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 certain debt documents) 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. Transfers of property were made from the Parent Company to the Guarantor Subsidiaries. As these transfers were transactions between entities under common control, the prior period financial information has been retrospectively adjusted for comparability purposes, as prescribed under authoritative guidance. None of the adjustments had any effect on the consolidated results for the current or prior periods presented.

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Balance Sheet as of September 30, 2016

	Parent Company (In thousands)	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	$73,351	$—	$—	$73,351
Receivables:				
Oil and natural gas sales	—	36,305	(533)	35,772
Joint interest and other	17,688	—	—	17,688
Income taxes	99,276	—	(99,276)	-
Total receivables	116,964	36,305	(99,809)	53,460
Prepaid expenses and other assets	13,048	3,097	—	16,145
Total current assets	203,363	39,402	(99,809)	142,956
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,700,543	2,236,795	—	7,937,338
Furniture, fixtures and other	20,898	—	—	20,898
Total property and equipment	5,721,441	2,236,795	—	7,958,236
Less accum. depreciation, depletion and amortization	5,345,682	2,025,995	—	7,371,677
Net property and equipment	375,759	210,800	—	586,559
Deferred income taxes	9,573	2,822	—	12,395
Restricted deposits for asset retirement obligations	26,767	—	—	26,767
Income tax receivables	52,097	—	—	52,097
Other assets	374,421	311,913	(674,511)	11,823
Total assets	$1,041,980	$564,937	$(774,320)	$832,597
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities:				
Accounts payable	$77,088	$6,221	$—	$83,309
Undistributed oil and natural gas proceeds	19,308	1,931	—	21,239
Asset retirement obligations	68,936	21,214	—	90,150
Accrued liabilities	19,669	99,180	(99,276)	19,573
Long-term debt	8,763	—	—	8,763
Total current liabilities	193,764	128,546	(99,276)	223,034
Long-term debt	1,014,221	—	—	1,014,221
Asset retirement obligations, less current portion	136,662	119,994	—	256,656
Other liabilities	375,330	—	(358,647)	16,683
Shareholders' deficit:				
Common stock	1	—	—	1
Additional paid-in capital	537,496	704,885	(704,885)	537,496
Retained earnings (deficit)	(1,191,327)	(388,488)	388,488	(1,191,327)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(677,997)	316,397	(316,397)	(677,997)
Total liabilities and shareholders' equity (deficit)	$1,041,980	$564,937	$(774,320)	$832,597

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Balance Sheet as of December 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$85,414	$—	$—	$85,414
Receivables:				
Oil and natural gas sales	2,742	32,263	—	35,005
Joint interest and other	121,190	—	(99,178)	22,012
Total receivables	123,932	32,263	(99,178)	57,017
Prepaid expenses and other assets	25,375	1,504	—	26,879
Total current assets	234,721	33,767	(99,178)	169,310
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,682,793	2,219,701	—	7,902,494
Furniture, fixtures and other	20,802	—	—	20,802
Total property and equipment	5,703,595	2,219,701	—	7,923,296
Less accum. depreciation, depletion and amortization	5,258,563	1,822,273	(147,589)	6,933,247
Net property and equipment	445,032	397,428	147,589	990,049
Deferred income taxes	27,251	344	—	27,595
Restricted deposits for asset retirement obligations	15,606	—	—	15,606
Other assets	498,782	266,748	(760,068)	5,462
Total assets	$1,221,392	$698,287	$(711,657)	$1,208,022
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities:				
Accounts payable	$100,282	$9,515	$—	$109,797
Undistributed oil and natural gas proceeds	20,463	976	—	21,439
Asset retirement obligations	63,716	20,619	—	84,335
Accrued liabilities	11,922	99,178	(99,178)	11,922
Total current liabilities	196,383	130,288	(99,178)	227,493
Long-term debt	1,196,855	—	—	1,196,855
Asset retirement obligations, less current portion	173,105	120,882	—	293,987
Other liabilities	329,129	—	(312,951)	16,178
Shareholders' deficit:				
Common stock	1	—	—	1
Additional paid-in capital	423,499	704,885	(704,885)	423,499
Retained earnings (deficit)	(1,073,413)	(257,768)	405,357	(925,824)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(674,080)	447,117	(299,528)	(526,491)
Total liabilities and shareholders' equity (deficit)	$1,221,392	$698,287	$(711,657)	$1,208,022

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Statement of Operations for the Three Months Ended September 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$44,585	$ 62,818	$ —	$ 107,403
Operating costs and expenses:				
Lease operating expenses	22,624	14,896	—	37,520
Production taxes	482	—	—	482
Gathering and transportation	2,103	3,058	—	5,161
Depreciation, depletion, amortization and accretion	21,959	29,861	(320)	51,500
Ceiling test write-down of oil and natural gas properties	28,305	25,317	4,290	57,912
General and administrative expenses	5,417	7,275	—	12,692
Derivative loss	412	—	—	412
Total costs and expenses	81,302	80,407	3,970	165,679
Operating loss	(36,717)	(17,589)	(3,970)	(58,276)
Loss of affiliates	(16,925)	—	16,925	—
Interest expense:				
Incurred	23,666	27	—	23,693
Capitalized	(48)	(27)	—	(75)
Gain on exchange of debt	123,960	—	—	123,960
Other expense, net	(73)	—	—	(73)
Income (loss) before income tax benefit	46,773	(17,589)	12,955	42,139
Income tax benefit	(3,125)	(664)	—	(3,789)
Net income (loss)	$49,898	$ (16,925)	$ 12,955	$ 45,928

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Statement of Operations for the Nine Months Ended September 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$119,011	$ 165,762	$ —	$ 284,773
Operating costs and expenses:				
Lease operating expenses	66,823	51,788	—	118,611
Production taxes	1,378	—	—	1,378
Gathering and transportation	6,125	10,526	—	16,651
Depreciation, depletion and amortization	65,230	99,956	7,540	172,726
Ceiling test write-down of oil and natural gas properties	28,305	110,709	140,049	279,063
General and administrative expenses	19,390	25,980	—	45,370
Derivative loss	2,861	—	—	2,861
Total costs and expenses	190,112	298,959	147,589	636,660
Operating loss	(71,101)	(133,197)	(147,589)	(351,887)
Loss of affiliates	(130,719)	—	130,719	—
Interest expense:				
Incurred	81,096	184	—	81,280
Capitalized	(336)	(184)	—	(520)
Gain on exchange of debt	123,960	—	—	123,960
Other expense, net	1,209	—	—	1,209
Loss before income tax benefit	(159,829)	(133,197)	(16,870)	(309,896)
Income tax benefit	(41,915)	(2,478)	—	(44,393)
Net loss	$(117,914)	$ (130,719)	$ (16,870)	$ (265,503)

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Statement of Operations for the Three Months Ended September 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$71,092	$ 55,136	$ —	$ 126,228
Operating costs and expenses:				
Lease operating expenses	29,721	15,318	—	45,039
Production taxes	889	—	—	889
Gathering and transportation	1,712	1,860	—	3,572
Depreciation, depletion, amortization and accretion	50,960	46,369	—	97,329
Ceiling test write-down of oil and natural gas properties	244,952	196,736		441,688
General and administrative expenses	8,590	7,925	—	16,515
Derivative gain	(10,231)	—	—	(10,231)
Total costs and expenses	326,593	268,208	—	594,801
Operating loss	(255,501)	(213,072)	—	(468,573)
Loss of affiliates	(129,061)	—	129,061	—
Interest expense:				
Incurred	27,911	843	—	28,754
Capitalized	(1,360)	(843)	—	(2,203)
Other expense, net	964	—	—	964
Loss before income tax expense (benefit)	(412,077)	(213,072)	129,061	(496,088)
Income tax expense (benefit)	65,491	(84,011)	—	(18,520)
Net loss	$(477,568)	$ (129,061)	$ 129,061	$ (477,568)

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Statement of Operations for the Nine Months Ended September 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$238,900	$164,301	$—	$403,201
Operating costs and expenses:				
Lease operating expenses	97,463	46,037	—	143,500
Production taxes	2,526	—	—	2,526
Gathering and transportation	7,046	6,143	—	13,189
Depreciation, depletion, amortization and accretion	180,334	145,804	—	326,138
Ceiling test write-down of oil and natural gas properties	616,947	337,903		954,850
General and administrative expenses	31,205	25,833	—	57,038
Derivative gain	(9,153)	—	—	(9,153)
Total costs and expenses	926,368	561,720	—	1,488,088
Operating loss	(687,468)	(397,419)	—	(1,084,887)
Loss of affiliates	(248,613)	—	248,613	—
Interest expense:				
Incurred	75,465	2,351	—	77,816
Capitalized	(3,659)	(2,351)	—	(6,010)
Other expense, net	2,647	—	—	2,647
Loss before income tax benefit	(1,010,534)	(397,419)	248,613	(1,159,340)
Income tax benefit	(17,422)	(148,806)	—	(166,228)
Net loss	$(993,112)	$(248,613)	$248,613	$(993,112)

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$(117,914)	$(130,719)	$(16,870)	$(265,503)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	65,230	99,956	7,540	172,726
Ceiling test write-down of oil and natural gas properties	28,305	110,709	140,049	279,063
Gain on exchange of debt	(123,960)	—	—	(123,960)
Debt issuance costs write-off/amortization of debt items	2,135	—	—	2,135
Share-based compensation	7,642	—	—	7,642
Derivative loss	2,861	—	—	2,861
Cash receipts on derivative settlements, net	4,746	—	—	4,746
Deferred income taxes	17,962	(2,478)	—	15,484
Loss of affiliates	130,719	—	(130,719)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	4,335	(4,041)	—	294
Joint interest and other receivables	4,281	—	—	4,281
Income taxes	(52,392)	—	—	(52,392)
Prepaid expenses and other assets	(14,535)	(46,758)	45,165	(16,128)
Asset retirement obligation settlements	(37,925)	(18,242)	—	(56,167)
Accounts payable, accrued liabilities and other	23,584	37,331	(45,165)	15,750
Net cash provided by (used in) operating activities	(54,926)	45,758	—	(9,168)
Investing activities:				
Investment in oil and natural gas properties and equipment	(17,473)	(6,589)	—	(24,062)
Changes in operating assets and liabilities associated with investing activities	2,269	(39,669)	—	(37,400)
Proceeds from sales of assets	1,000	500	—	1,500
Purchases of furniture, fixtures and other	(96)	—	—	(96)
Net cash used in investing activities	(14,300)	(45,758)	—	(60,058)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	340,000	—	—	340,000
Repayments of long-term debt – revolving bank credit facility	(340,000)	—	—	(340,000)
Issuance of 1.5 Lien Term Loan	75,000	—	—	75,000
Debt exchange costs	(17,920)	—	—	(17,920)
Other	83	—	—	83
Net cash provided by financing activities	57,163	—	—	57,163
Increase in cash and cash equivalents	(12,063)	—	—	(12,063)
Cash and cash equivalents, beginning of period	85,414	—	—	85,414
Cash and cash equivalents, end of period	$73,351	$—	$—	$73,351

W&T OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$ (993,112)	$ (248,613)	$ 248,613	$ (993,112)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	180,334	145,804	—	326,138
Ceiling test write-down of oil and natural gas properties	616,947	337,903	—	954,850
Debt issuance costs write-off/ amortization of debt items	2,862	—	—	2,862
Share-based compensation	8,313	—	—	8,313
Derivative gain	(9,153)	—	—	(9,153)
Cash receipts on derivative settlements	2,139	—	—	2,139
Deferred income taxes	(50,743)	(115,515)	—	(166,258)
Loss of affiliates	248,613	—	(248,613)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	26,022	(2,735)	—	23,287
Joint interest and other receivables	1,210	—	—	1,210
Income taxes	33,002	(33,291)	—	(289)
Prepaid expenses and other assets	(47,057)	114,888	(51,139)	16,692
Asset retirement obligations	(22,901)	(2,614)	—	(25,515)
Accounts payable, accrued liabilities and other	(57,851)	341	51,139	(6,371)
Net cash provided by (used in) operating activities	(61,375)	196,168	—	134,793
Investing activities:				
Investment in oil and natural gas properties and equipment	(29,930)	(162,881)	—	(192,811)
Changes in operating assets and liabilities associated with investing activities	(30,731)	(34,732)	—	(65,463)
Investment in subsidiary	(1,445)	—	1,445	—
Purchases of furniture, fixtures and other	(1,185)	—	—	(1,185)
Net cash used in investing activities	(63,291)	(197,613)	1,445	(259,459)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	263,000	—	—	263,000
Repayments of long-term debt – revolving bank credit facility	(445,000)	—	—	(445,000)
Issuance of Second Lien Term Loan	297,000	—	—	297,000
Debt issuance costs	(6,591)	—	—	(6,591)
Other	54	—	—	54
Investment from parent	—	1,445	(1,445)	—

Net cash provided by financing activities	108,463	1,445	(1,445)	108,463
Decrease in cash and cash equivalents	(16,203)	—	—	(16,203)
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	$7,463	$—	$—	$ 7,463

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"), which 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, 2015 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 with operations offshore in the Gulf of Mexico. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 54 offshore fields in federal and state waters (50 producing and four fields capable of producing). We currently have under lease approximately 750,000 gross acres, with approximately 450,000 gross acres on the shelf and approximately 300,000 gross acres in the deepwater. 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.

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 nine months ended September 30, 2016 were comprised of 47.4% oil and condensate, 10.1% NGLs and 42.5% 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 oil equivalent ("Boe") for oil, NGLs and natural gas has differed significantly from time to time. For the nine months ended September 30, 2016, revenues from the sale of oil and NGLs made up 74.6% of our total revenues compared to 73.9% for the same period in 2015. For the nine months ended September 30, 2016, our combined total production was 9.8% lower than the same period in 2015, with natural gas production having the largest decline. For the nine months ended September 30, 2016, our total revenues were 29.4% lower than the same period in 2015 due primarily to significantly lower realized prices for oil, NGLs and natural gas. See Results of Operations – Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015 in this Item for additional information on our revenues and production.

On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our Unsecured Senior Notes due 2019 for new secured notes and common stock. At the same time, we closed on a new $75.0 million, 1.5 Lien Term Loan and in conjunction; two amendments were made effective under our Credit Agreement. See Financial Statements - Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q and Liquidity and Capital Resources in this Item for additional information.

On October 15, 2015, we sold our interests in the Yellow Rose onshore field in the Permian Basin to Ajax. Our interest in the field covered approximately 25,800 net acres. During the nine months ended September 30, 2015, the Yellow Rose field accounted for approximately 6% and 7% of our production and revenues, respectively. In connection with the sale, we retained a non-expense bearing ORRI equal to a variable percentage in production from the working interests sold, which percentage varies on a sliding scale from one percent for each month that the NYMEX prompt month contract trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel. Internal estimates of proved reserves at the date of the sale were 19.0 million barrels of oil equivalent ("MMBoe"), consisting of approximately 71% oil, 11% NGL and 18% natural gas. Including adjustments from an effective date of January 1, 2015, the adjusted sales price was $370.9 million of cash and the buyer assumed the ARO associated with our interests in the Yellow Rose field, which we had estimated at $6.9 million at the time of the sale, and the buyer assumed other liabilities of $1.1 million. We used a portion of the proceeds of the sale to repay all the outstanding borrowings under our revolving bank credit facility, while the remaining balance of approximately $98 million was added to available cash.

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. Beginning in the second half of 2014 and continuing through September 2016, crude oil prices have fallen dramatically from a peak of over $100 per barrel for WTI in June 2014. In addition, prices of NGLs and natural gas have fallen significantly from 2014 levels. Commodity prices for WTI and Brent crude oil were approximately the same level in the third quarter 2016 compared to the second quarter of 2016, while the average price of natural gas improved in the third quarter of 2016 compared to the second quarter of 2016. The average prices for both commodities for the nine months ended September 30, 2016 are below levels for the comparative 2015 period. While U.S. production of crude oil and other petroleum liquids declined in the third quarter of 2016 from the third quarter 2015, the overall market for the third quarter of 2016 remains in an oversupply position. Selected issues and data points are described below.

The U.S. Energy Information Administration ("EIA") estimates the worldwide crude oil and petroleum liquids supply will exceed demand in 2016, resulting in crude oil and other petroleum liquids inventories increasing by 0.7 million barrels per day. While the estimate for 2016 remains in an oversupply position, revised estimates for production were decreased and consumption increased from the previous forecast and has the market moving closer to being in balance for 2016 than previous estimates, but for 2017, EIA is now forecasting an oversupply compared to the previous forecast of being in balance. EIA estimates inventory builds in each quarter of 2016 and the first half of 2017, and forecasts the first inventory withdrawal occurring in the third quarter of 2017. Comparing the nine months ended September 30, 2016 to the same period in 2015, worldwide supply increased by 0.2 million barrels per day, primarily due to increases from OPEC, while U.S. supply decreased between the two periods. EIA's estimate for 2016 has supply increasing over 2015 by 0.2 million barrels per day, with Iran accounting for most of the increase, partially offset by decreases primarily in the U.S. EIA's forecast for supply from OPEC does not assume any production cuts from collaborative agreements. EIA's estimate has consumption increasing in 2016 over 2015 by 1.3 million barrels per day, with the increases coming primarily from China and other Asian countries. EIA's consumption forecast incorporates Europe's consumption being flat between the two years, with no material impact of the uncertainty related to the United Kingdom leaving the European Union.

According to data provided by EIA, U.S. production of crude oil (excluding other petroleum liquids) decreased in the nine months ended September 30, 2016 by 7% compared to the same period in 2015. EIA's estimate for 2016 of U.S. crude oil production is a decrease of 7% from 2015, and for 2017, estimates a further decrease of 2% from 2016. As noted below, the number of rigs drilling for oil decreased dramatically in 2015 and further decreased through September 2016.

During the nine months ended September 30, 2016, our average realized oil sales price was $35.01, down from $47.81 per barrel (26.8% lower) for the same period in 2015. The two primary benchmarks are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $41.35 per barrel for the nine months ended September 30, 2016, down from $50.94 per barrel (18.8% lower) for the same period in 2015. Brent crude average oil prices decreased to $41.86 per barrel for the nine months ended September 30, 2016, down from $55.31 per barrel (24.3% lower) for the same period in 2015. Prices for WTI and Brent as of September 30, 2016 were approaching $50.00 per barrel, and were $47.72 per barrel and $48.24 per barrel, respectively. Our average realized oil sales price ($35.01 per barrel compared to a WTI benchmark price of $41.35 per barrel) for the nine months ended September 30, 2016 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 during 2016 was produced offshore in the Gulf of Mexico and is characterized as Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS"), Poseidon 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. For example, the monthly average differentials of WTI versus LLS, HLS and Poseidon for the nine months ended September 30, 2016 were a positive $1.79 and $0.87, and a negative $3.58 per barrel, respectively, compared to positive $4.26 and $3.39, and a negative $0.27 per barrel, respectively, for the same period in 2015. The majority of our crude oil is priced similar to Poseidon and, therefore, is experiencing negative differentials. In addition, a few of our crude oil fields have a negative quality bank adjustment.

EIA projects average crude oil prices for WTI and Brent to decrease for the year 2016 compared to 2015 by approximately $6.00 per barrel and $9.00 per barrel, respectively, and to increase in 2017 by approximately $7.00 per barrel for each. Their estimate notes that the current values for futures and options indicate high volatility. Other factors noted that may have a significant impact on future crude oil prices include whether OPEC can reach an agreement on production caps and the extent of compliance against production targets. EIA notes the recent U.S. onshore activity has created the expectation of increased U.S. production in 2017causing EIA to lower its forecast of the 2017 Brent price. In addition, the strength in the U.S. dollar relative to other currencies also has an impact on crude pricing. Because all barrels are traded in U.S. dollars, as the U.S. dollar gains strength, crude prices are lower in U.S. dollars but are more expensive in other currencies.

During the nine months ended September 30, 2016, our average realized NGLs sales price decreased 9.8% compared to the same period in 2015. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the nine months ended September 30, 2016, average prices for domestic ethane increased 5% and average domestic propane prices decreased 3% from the same period in 2015. Average price changes for other domestic NGLs were a decrease of 19% to no change between the two periods. Per EIA, production of ethane and propane increased in the nine months ended September 30, 2016 over the same period in 2015 by 15% and 3%, respectively. Ethane inventories are much higher than the prior year, increasing 65%, and although ethane prices have increased from prior year levels, ethane prices remain low compared to historical levels. Propane inventory levels are at their normal build going into the heating season and are 4% higher than the comparable period of 2015. As long as the price ratio of crude oil to natural gas remains wide (as measured on a six to one energy equivalency), the production of NGLs may continue to be high relative to historical norms, which would in turn suggest continued weak prices, or possibly further price reductions, especially for the prices of ethane and propane. Many natural gas processing facilities have been and from time to time, will likely continue re-injecting ethane back into the natural gas stream after processing due to insufficient ethane demand, which negatively impacts production and natural gas prices. Ethane demand is expected to increase in 2017 as petrochemical plants and expansion projects that consume ethane come online.

During the nine months ended September 30, 2016, our average realized natural gas sales price decreased 17.4% compared to the same period in 2015. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 15.5% lower in the nine months ended September 30, 2016 from the same period in 2015. 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. However, with the surplus of natural gas that has plagued the industry since 2012, natural gas prices have been weak and the fluctuations in prices have been limited to the lower end of the price range. Prices in the third quarter of 2016 increased from the second quarter of 2016 by over 30%, but price levels continue to be very weak. Per EIA, the increase was attributable to higher demand for electricity generation, expected lower-than-normal inventory builds and the expectation for colder temperatures this coming winter compared to last winter. The U.S. natural gas inventories at the end of September 2016 were approximately 2% higher than a year earlier and 7% higher than the five year average. The forecast has inventories lower at December 2016 compared to the prior year. U.S. consumption was flat in the nine months ended September 30, 2016, with electricity consumption increases offsetting residential usage. U.S. supplies decreased 2% due primarily to lower production in the lower 48 states.

The average price of natural gas continues 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 (iv) higher inventory levels and (v) re-injecting ethane into the natural gas stream as indicated above, which increases the natural gas supply.

EIA projects natural gas prices to increase, relatively speaking, in the fourth quarter of 2016 compared to the third quarter of 2016, but lower for the full year of 2016 compared to 2015. U.S. supply is projected to be lower than consumption in 2016 by 1%, but EIA forecasts production to increase in 2017 and be 1% higher than consumption. Natural gas usage for power generation is expected to remain in the 33%-34% range for 2016 and 2017, which is slightly higher than 2015 levels due to lower natural gas prices compared to coal and new Federal regulations discouraging coal usage.

During the nine months ended September 30, 2016, the number of rigs drilling for oil and natural gas in the U.S. was significantly below 2014 levels due to lower crude oil and natural gas prices. According to Baker Hughes, the oil rig count at December 2014, December 2015 and September 2016 was 1,482, 536 and 425, respectively. The number of rigs drilling for oil as of September 2016 increased by 84 oil rigs from June 2016, which is the first quarterly increase since 2014. The U.S. natural gas rig count at December 2014, December 2015 and September 2016 was 328, 162 and 96, respectively. The U.S. natural gas rig count as of September 2016 increased by seven natural gas rigs from June 2016, which was also the first quarterly increase since 2014. In the Gulf of Mexico, there were 54 rigs (42 oil and 12 natural gas) at the end of 2014; 25 rigs (20 oil and five natural gas) as of the end of 2015; and 21 rigs (20 oil and one natural gas) as of September 2016. The majority of working rigs in the Gulf of Mexico are currently “floaters” with very few jack-up rigs working.

As required by the full cost accounting rules, we perform our ceiling test calculation each quarter using the SEC pricing guidelines, which require using the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price adjusted for price differentials. The average price using the SEC required methodology at September 30, 2016 was $38.17 per barrel for WTI crude oil and $2.28 per MMBtu for Henry Hub natural gas before adjustments. Due to the decrease in the 12-month average price for both crude oil and natural gas, we recorded ceiling test write-downs of the carrying value of our oil and natural gas properties in the third quarter and the nine months ended September 30, 2016 of $57.9 million and $279.1 million, respectively. For the nine months ended September 30, 2015 and full year of 2015, the ceiling test write-downs were $954.9 million and $987.2 million, respectively. Incurrence of further write downs is dependent primarily on the price of crude oil and natural gas, but also is affected by quantities of proved reserves, future development costs and future lease operating costs.

We performed a pro-forma calculation to determine if a further ceiling test impairment write-down would be likely in the fourth quarter of 2016 based only on changes to prices using the assumptions that projected prices are the same as most recently published first-day-of-the month prices to compute a pro-forma 12-month average. In this pro-forma calculation, no changes were assumed for proved reserves from the September 30, 2016 levels other than price and no changes were assumed for other factors. The pro-forma calculation indicated that there would have been a lower ceiling-test write down for the third quarter of 2016 using these pro-forma prices. This pro-forma calculation may not be predictive of the fourth quarter of 2016, as other factors besides price will impact the ceiling test calculation.

During 2015, we were notified by the BOEM that the Company was no longer eligible for any exemptions set forth in the regulations and then-current supplemental bonding procedures of the BOEM related to decommissioning obligations. In February and March 2016, we received several demands from the BOEM ordering that we provide additional security in the aggregate of $260.8 million. We filed appeals and the IBLA has agreed to stay the effectiveness of the orders. This is the third stay that we have received from the IBLA, and their latest stay extends the effectiveness to January 31, 2017. We submitted a proposal for a tailored plan of compliance in May 2016 under the BOEM's then-current supplemental bonding procedures in NTL #2008-N07. Subsequently, the BOEM issued NTL #2016-N01 to replace NTL #2008-N07, effective September 2016, and we submitted a revised proposed tailored plan of compliance to the BOEM incorporating requirements of the new NTL. We continue to have discussions with the BOEM regarding these matters. These matters are more fully discussed in the Liquidity and Capital Resources section of this Item II of this Form 10-Q.

Due to the deterioration of commodity prices and the outlook for the remainder of 2016, our 2016 capital expenditure budget is set well below prior year levels. Capital expenditures incurred for 2015 and 2014 were $231 million and $630 million, respectively. We have the flexibility to make this reduction to our 2016 capital expenditure budget because we have no long term rig commitments and no pressure from partners to drill or complete a well. Moreover, we expect our deepwater projects completed in 2015, combined with new production from our Ewing Bank 910 A-8 well, will partially offset normal production declines from existing wells during 2016 and the loss of production from the sale of Yellow Rose in the fourth quarter of 2015. However, unplanned downtime, pipeline maintenance, and well performance are factors leading to lower estimated production in 2016 from 2015. We do not expect to lose drilling opportunities at this spending level and have no significant lease expiration issues in 2016. In addition, our plans include spending $74 million in 2016 for ARO, which is an increase from $33 million spent on ARO in 2015. We are currently drilling the A-18 well at Ship Shoal 349 (Mahogany), which, if successful, will benefit production in 2017.

With respect to our costs, we have seen relatively significant reductions in our lease operating expenses and general and administrative expenses as a result of our cost reduction programs, which include headcount and contractor usage reductions, combined with reduced rates from vendors for supplies, equipment and contract labor. These cost reduction programs and reduced supplier rates have also lowered capital expenditures, ARO settlements and ARO estimates.

Our short term focus is on liquidity, cost reductions, fulfilling our obligations and making investments with short payback time frames. In light of our limited access to capital and liquidity, we are continually assessing our plans and currently expect to increase capital investments above 2016 levels, and we are considering possible divestitures. 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, 2015, Item 1A, Risk Factors, and Risk Factors under Part II, Item 1A of this Form 10-Q 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 September 30, 2016	2015	Change	%	Nine Months Ended September 30, 2016	2015	Change	%
	(In thousands, except percentages and per share data)							
Financial:								
Revenues:								
Oil	$70,974	$86,521	$(15,547)	(18.0)%	$193,661	$276,127	$(82,466)	(29.9)%
NGLs	6,696	6,515	181	2.8 %	18,709	21,792	(3,083)	(14.1)%
Natural gas	29,135	31,355	(2,220)	(7.1)%	69,238	100,015	(30,777)	(30.8)%
Other	598	1,837	(1,239)	(67.4)%	3,165	5,267	(2,102)	(39.9)%
Total revenues	107,403	126,228	(18,825)	(14.9)%	284,773	403,201	(118,428)	(29.4)%
Operating costs and expenses:								
Lease operating expenses	37,520	45,039	(7,519)	(16.7)%	118,611	143,500	(24,889)	(17.3)%
Production taxes	482	889	(407)	(45.8)%	1,378	2,526	(1,148)	(45.4)%
Gathering and transportation	5,161	3,572	1,589	44.5 %	16,651	13,189	3,462	26.2 %
Depreciation, depletion, amortization and accretion	51,500	97,329	(45,829)	(47.1)%	172,726	326,138	(153,412)	(47.0)%
Ceiling test write-down of oil and natural gas properties	57,912	441,688	(383,776)	(86.9)%	279,063	954,850	(675,787)	(70.8)%
General and administrative expenses	12,692	16,515	(3,823)	(23.1)%	45,370	57,038	(11,668)	(20.5)%
Derivative (gain) loss	412	(10,231)	10,643	NM	2,861	(9,153)	12,014	NM
Total costs and expenses	165,679	594,801	(429,122)	(72.1)%	636,660	1,488,088	(851,428)	(57.2)%
Operating loss	(58,276)	(468,573)	410,297	(87.6)%	(351,887)	(1,084,887)	733,000	(67.6)%
Interest expense, net of amounts capitalized	23,618	26,551	(2,933)	(11.0)%	80,760	71,806	8,954	12.5 %
	123,960	—	123,960	NM	123,960	—	123,960	NM

Gain on exchange of debt								
Other (income) expense, net	(73)	964	(1,037)	NM	1,209	2,647	(1,438)	(54.3)%
Income (loss) before income tax benefit	42,139	(496,088)	538,227	(108.5)%	(309,896)	(1,159,340)	849,444	(73.3)%
Income tax benefit	(3,789)	(18,520)	14,731	(79.5)%	(44,393)	(166,228)	121,835	(73.3)%
Net income (loss)	$45,928	$(477,568)	$523,496	(109.6)%	$(265,503)	$(993,112)	$727,609	(73.3)%
Basic and diluted income (loss) per common share	$0.48	$(6.29)	$6.77	NM	$(3.25)	$(13.08)	$9.83	(75.2)%

NM – not meaningful

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Change	% [2]	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Change	% [2]
Operating: [1]								
Net sales:								
Oil (MBbls)	1,791	1,973	(182)	(9.2)%	5,532	5,776	(244)	(4.2)%
NGLs (MBbls)	372	389	(17)	(4.4)%	1,180	1,241	(61)	(4.9)%
Natural gas (MMcf)	9,935	11,635	(1,700)	(14.6)%	29,696	35,470	(5,774)	(16.3)%
Total oil equivalent (MBoe)	3,819	4,302	(483)	(11.2)%	11,661	12,928	(1,267)	(9.8)%
Total natural gas equivalents (MMcfe)	22,912	25,810	(2,898)	(11.2)%	69,967	77,569	(7,602)	(9.8)%
Average daily equivalent sales (Boe/day)	41,508	46,757	(5,249)	(11.2)%	42,559	47,356	(4,797)	(10.1)%
Average daily equivalent sales (Mcfe/day)	249,045	280,105	(31,060)	(11.1)%	255,355	284,137	(28,782)	(10.1)%
Average realized sales prices:								
Oil ($/Bbl)	$39.62	$43.85	$(4.23)	(9.6)%	$35.01	$47.81	$(12.80)	(26.8)%
NGLs ($/Bbl)	18.02	16.74	1.28	7.6 %	15.85	17.57	(1.72)	(9.8)%
Natural gas ($/Mcf)	2.93	2.69	0.24	8.9 %	2.33	2.82	(0.49)	(17.4)%
Oil equivalent ($/Boe)	27.97	28.92	(0.95)	(3.3)%	24.15	30.78	(6.63)	(21.5)%
Natural gas equivalent ($/Mcfe)	4.66	4.82	(0.16)	(3.3)%	4.02	5.13	(1.11)	(21.6)%
Average per Boe ($/Boe):								
Lease operating expenses	$9.82	$10.47	$(0.65)	(6.2)%	$10.17	$11.10	$(0.93)	(8.4)%
Gathering and transportation	1.35	0.83	0.52	62.7 %	1.43	1.02	0.41	40.2 %
Production costs	11.17	11.30	(0.13)	(1.2)%	11.60	12.12	(0.52)	(4.3)%
Production taxes	0.13	0.21	(0.08)	(38.1)%	0.12	0.20	(0.08)	(40.0)%
DD&A	13.49	22.62	(9.13)	(40.4)%	14.81	25.23	(10.42)	(41.3)%
General and administrative expenses	3.32	3.84	(0.52)	(13.5)%	3.89	4.41	(0.52)	(11.8)%
	$28.11	$37.97	$(9.86)	(26.0)%	$30.42	$41.96	$(11.54)	(27.5)%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$1.64	$1.74	$(0.10)	(5.7)%	$1.70	$1.85	$(0.15)	(8.1)%
Gathering and transportation	0.23	0.14	0.09	64.3 %	0.24	0.17	0.07	41.2 %
Production costs	1.87	1.88	(0.01)	(0.5)%	1.94	2.02	(0.08)	(4.0)%
Production taxes	0.02	0.03	(0.01)	(33.3)%	0.02	0.03	(0.01)	(33.3)%
DD&A	2.25	3.77	(1.52)	(40.3)%	2.47	4.20	(1.73)	(41.2)%
General and administrative expenses	0.55	0.64	(0.09)	(14.1)%	0.65	0.74	(0.09)	(12.2)%

	$4.69	$6.32	$(1.63)	(25.8)%	$5.08	$6.99	$(1.91)	(27.3)%

(1) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one 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	Mcf - thousand cubic feet
Boe - barrel of oil equivalent	Mcfe - thousand cubic feet equivalent
MBbls - thousand barrels for crude oil, condensate or NGLs	MMcf - million cubic feet
MBoe - thousand barrels of oil equivalent	MMcfe - million cubic feet equivalent

Drilled and Completed Wells

During the nine months ended September 30, 2016 and 2015, we drilled one and five offshore wells, respectively, all of which were productive. During 2015, we drilled onshore wells, which were included with the sale of the Yellow Rose field in October 2015 and we have sold, relinquished or let expire essentially all onshore leasehold interests.

Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015

Revenues. Total revenues decreased $18.8 million, or 14.9%, to $107.4 million for the third quarter of 2016 as compared to the third quarter of 2015. Oil revenues decreased $15.5 million, or 18.0%, NGLs revenues increased $0.2 million, or 2.8%, natural gas revenues decreased $2.2 million, or 7.1% and other revenues decreased $1.2 million. The decrease in oil revenues was attributable to a 9.6% decrease in the average realized sales price to $39.62 per barrel for the third quarter of 2016 from $43.85 per barrel for the third quarter of 2015 and a decrease of sales volumes of 9.2%. The increase in NGLs revenues was attributable to a 7.6% increase in the average realized sales price to $18.02 per barrel for the third quarter of 2016 from $16.74 per barrel for the third quarter of 2015, partially offset by a decrease of 4.4% in sales volumes. The decrease in natural gas revenues resulted from a decrease of 14.6% in sales volumes, partially offset by a 8.9% increase in the average realized natural gas sales price to $2.93 per Mcf for the third quarter of 2016 from $2.69 per Mcf for the third quarter of 2015. Overall, production declined 0.5 MMBoe (11.2%). We experienced increases in production at the Mississippi Canyon 698 field (“Big Bend”) and the Mississippi Canyon 782 field (“Dantzler”), which began production in the fourth quarter of 2015. Also, production increases were achieved at the Ewing Bank 910 field, the East Cameron 321 field and the Main Pass 98 field. Offsetting these production increases were production declines primarily from the sale of the Yellow Rose field in October 2015 (0.3 MMBoe); decreases at Ship Shoal 349 (“Mahogany”), Mississippi Canyon 582 (Medusa), Mississippi Canyon 243 (“Matterhorn”), Garden Banks 302 (“Power Play”), and other fields due to pipeline, operational issues and natural production declines; and production deferrals affecting various fields. Production deferrals, which occurred at Mahogany and other locations, were attributable to third-party pipeline outages, operational issues, and maintenance. During the third quarter of 2016, we revised our procedures in estimating production deferrals to include only those properties that have returned to production or are in current plans to return to production. Our estimate of production deferrals utilizing this revised methodology was 0.2 MMBoe during the third quarter of 2016 compared to 0.4 MMBoe during the third quarter of 2015 using our revised procedures.

Revenues from oil and liquids as a percent of our total revenues were 72.3% for the third quarter of 2016 compared to 73.7% for the third quarter of 2015. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 45.5% for the third quarter of 2016 compared to 38.2% for the third quarter of 2015.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $7.5 million, or 16.7%, to $37.5 million in the third quarter 2016 compared to the third quarter of 2015. On a per Boe basis, lease operating expenses decreased to $9.82 per Boe during the third quarter of 2016 compared to $10.47 per Boe during the third quarter of 2015. On a component basis, base lease operating expenses decreased $1.1 million, workover expense decreased $4.9 million, insurance premiums decreased $1.7 million and facilities maintenance increased $0.2 million. Base lease operating expenses decreased primarily due to lower costs from service providers and elimination of field expenses related to the Yellow Rose field, which was sold in October 2015; partially offset by increases in expenses related to our new deepwater fields at Dantzler and Big Bend and by lower production handling fees (cost offsets) at our Matterhorn field. The decrease in workover costs was primarily due to the sale of the Yellow Rose field, and for valve repairs and other work at Garden Banks 293 performed in 2015. Insurance premium reductions are primarily due to revisions in the Energy Package related to named windstorms, which became effective in June 2016.

Production taxes. Production taxes decreased $0.4 million to $0.5 million for the third quarter of 2016 compared to the third quarter of 2015 primarily due to the sale of the Yellow Rose field in October 2015. 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 increased $1.6 million to $5.2 million for the third quarter of 2016 compared to the third quarter of 2015 primarily due to new production increases from Big Bend and Dantzler, both of which began producing in the fourth quarter of 2015.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $13.49 per Boe for the third quarter of 2016 from $22.62 per Boe for the third quarter of 2015. On a nominal basis, DD&A decreased to $51.5 million, (47.1%), for the third quarter of 2016 from $97.3 million for the third quarter of 2015. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2015 and the first half of 2016 (the third quarter 2016 ceiling test write-down will not affect the DD&A rate until the fourth quarter of 2016) and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field proved reserves. Other factors affecting the DD&A rate are lower future development costs on remaining reserves and lower proved reserves volumes.

Ceiling test write-down of oil and natural gas properties. For the third quarter of 2016, we recorded a non-cash ceiling test write-down of $57.9 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is primarily the result of lower prices for our proved reserves. For the third quarter of 2015, the ceiling test write-down was $441.7 million. See Financial Statements and Supplementary Data – Note 1 - Basis of Presentation under Part I, Item 1 of this Form 10-Q, which provides a description of the ceiling test limit determination, and above under the section Overview in this Item regarding our prospects for a future ceiling test write-down.

General and administrative expenses (“G&A”). G&A decreased to $12.7 million, (23.1%), for the third quarter of 2016 from $16.5 million for the third quarter of 2015 primarily due to reclassifying transaction costs related to the Exchange Transaction previously recorded as G&A to the gain on exchange of debt described below. In addition, decreases in headcount related expense (salaries, benefits, and contractor expenses) and elimination of certain employee benefits contributed to the decrease. G&A on a per BOE basis was $3.32 per Boe for the third quarter of 2016 compared to $3.84 per Boe for the third quarter of 2015.

Derivative (gain) loss. For the third quarter of 2016, there was a $0.4 million net derivative loss recorded for derivative contracts for crude oil and natural gas as increased prices for crude oil and natural gas resulted in a reversal of previously recorded gains for open derivatives contracts. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For the third quarter of 2015, there was a $10.2 million net derivative gain recorded for derivative contracts for crude oil and natural gas.

Interest expense. Interest expense incurred was $23.7 million in the third quarter of 2016, compared to $28.8 million in the third quarter of 2015. The decrease was primarily attributable to the Exchange Transaction. Interest expense was reduced for the Unsecured Senior Notes exchanged on September 7, 2016. For the New Debt issued in the Exchange Transaction, undiscounted future cash flows (principal, PIK and cash interest) are recorded as the carrying value of the New Debt under ASC 470-60; therefore, no interest expense was recorded for the New Debt for the period of September 7, 2016 to September 30, 2016. In addition, interest expense was lower due to lower average borrowings on the revolving bank credit facility. During the third quarter of 2016 and 2015, $0.1 million and $2.2 million, respectively, of interest costs were capitalized related to unevaluated oil and natural gas properties. The decrease is primarily attributable to the sale of the Yellow Rose field in October 2015 and reclassification of certain unevaluated properties to the full cost pool during 2016 and the full year of 2015.

Gain on exchange of debt. A gain of $124.0 million was recorded related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as undiscounted future cash flows of the New Debt, plus the fair value of the common stock issued and deal transaction costs were less than the sum of the carrying value of the Unsecured Senior Notes exchanged combined with the funds received from the 1.5 Lien Term Loan issued. See Liquidity and Capital Resources in this Item for a table on the calculation of the gain.

Other (income) expense, net. During the third quarter of 2016 and 2015, other income, net, was $0.1 million and other expense, net, was $1.0 million, respectively. During the third quarter of 2015, a net loss on sale of assets of $1.0 million was recorded primarily related to the sale of computer equipment used for backup purposes.

Income tax benefit. Our income tax benefit for the third quarter of 2016 and 2015 was $3.8 million and $18.5 million, respectively. Our annualized effective tax rate for the third quarter of 2016 using book pre-tax income is not meaningful primarily due to the book gain associated with the Exchange Transaction. We recognized a tax benefit in the third quarter of 2016 primarily due to changes in the valuation allowance and deferred tax assets. For the third quarter 2015, our effective tax rate was 3.7%, and differs from the federal statutory rate of 35% primarily due to the valuation allowance recorded for our deferred tax assets. During the three months ended September 30, 2016 and 2015, we recorded a decrease to the valuation allowance decrease of $19.1 million and an increase to the valuation allowance of $156.2 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to generate 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.

Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015

Revenues. Total revenues decreased $118.4 million, or 29.4%, to $284.8 million for the nine months ended September 30, 2016 as compared to the same period in 2015. Oil revenues decreased $82.5 million, or 29.9%, NGLs revenues decreased $3.1 million, or 14.1%, natural gas revenues decreased $30.8 million, or 30.8% and other revenues decreased $2.1 million. The decrease in oil revenues was attributable to a 26.8% decrease in the average realized sales price to $35.01 per barrel for the nine months ended September 30, 2016 from $47.81 per barrel for the same period in 2015, with sales volumes down by 4.2%. The decrease in NGLs revenues was attributable to a 9.8% decrease in the average realized sales price to $15.85 per barrel for the nine months ended September 30, 2016 from $17.57 per barrel for the same period in 2015, with a decrease of 4.9% in sales volumes. The decrease in natural gas revenues resulted from a 17.4% decrease in the average realized natural gas sales price to $2.33 per Mcf for the nine months ended September 30, 2016 from $2.82 per Mcf for the same period in 2015, with a decrease of 16.3% in sales volumes. Overall, production declined 1.3 MMBoe (9.8%). We experienced increases in production at Big Bend and Dantzler, which began production in the fourth quarter of 2015. Also, production increases were achieved at the Ewing Bank 910 field, the Main Pass 108 field, Main Pass 98 field and the Mississippi Canyon 582 field (Medusa). Offsetting these production increases were production declines primarily from the sale of the Yellow Rose field in October 2015 (0.8 MMBoe); and decreases at Mahogany, Matterhorn, Power Play, Wrigley, and other fields due to pipeline, operational issues and natural production; and production deferrals affecting various fields. Production deferrals, which occurred at multiple locations, were attributable to third-party pipeline outages, operational issues, and maintenance.

Revenues from oil and liquids as a percent of our total revenues were 74.6% for the nine months ended September 30, 2016 compared to 73.9% for the same period in 2015. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 45.3% for the nine months ended September 30, 2016 compared to 36.7% for the same period in 2015.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $24.9 million, or 17.3%, to $118.6 million in the nine months ended September 30, 2016 compared to the same period in 2015. On a per Boe basis, lease operating expenses decreased to $10.17 per Boe during the nine months ended September 30, 2016 compared to $11.10 per Boe during the same period in 2015. On a component basis, base lease operating expenses decreased $10.2 million, workover expense decreased $9.2 million, insurance premiums decreased $4.9 million and facilities maintenance decreased $0.8 million. Base lease operating expenses decreased primarily due to lower costs from service providers and elimination of field expenses related to the sale of the Yellow Rose field, which was sold in October 2015; partially offset by increases in expenses related to our new deepwater fields at Dantzler and Big Bend and lower production handling fees (cost offsets) at our Matterhorn field. The decrease in workover costs was primarily due to the sale of the Yellow Rose field and various activities that occurred in the 2015 period that did not reoccur in the 2016 period. Insurance premium reductions are primarily due to revisions in the Energy Package related to named windstorms.

Production taxes. Production taxes decreased $1.1 million to $1.4 million for the nine months ended September 30, 2016 compared to the same period in 2015 primarily due to the sale of the Yellow Rose field in October 2015. 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 increased $3.5 million to $16.7 million for the nine months ended September 30, 2016 compared to the same period in 2015 primarily due to new production increases from Big Bend and Dantzler, both of which began producing in the fourth quarter of 2015.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $14.81 per Boe for the nine months ended September 30, 2016 from $25.23 per Boe for the same period in 2015. On a nominal basis, DD&A decreased to $172.7 million, (47.0%), for the nine months ended September 30, 2016 from $326.1 million for the same period in 2015. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2015 and the first half of 2016 (the third quarter 2016 ceiling test write-down will not affect the DD&A rate until the fourth quarter of 2016) and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field proved reserves. Other factors affecting the DD&A rate are lower future development costs on remaining proved reserves and lower proved reserves volumes.

Ceiling test write-down of oil and natural gas properties. For the nine months ended September 30, 2016, we recorded a non-cash ceiling test write-down of $279.1 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is the result of decreases in prices for all three commodities we sell, which are crude oil, NGLs and natural gas. For the nine months ended September 30, 2015, the ceiling test write-down was $954.9 million. See Financial Statements and Supplementary Data – Note 1 - Basis of Presentation under Part I, Item 1 of this Form 10-Q, which provides a description of the ceiling test limit determination, and above under the section Overview in this Item regarding our prospects for a future ceiling test write-down.

General and administrative expense. G&A decreased to $45.4 million, (20.5%), for the nine months ended September 30, 2016 from $57.0 million for the same period in 2015 primarily due to reclassifying transaction costs related to the Exchange Transaction previously recorded as G&A to the gain on exchange of debt described below. In addition, decreases in headcount related expense (salaries, benefits, and contractor expenses), elimination of certain employee benefits, increased reimbursements from stop-loss medical policies, and reductions in legal settlements contributed to the decrease. Partially offsetting were higher legal costs. G&A on a per BOE basis was $3.89 per Boe for the nine months ended September 30, 2016 compared to $4.41 per Boe for the same period in 2015.

Derivative (gain) loss. For the nine months ended September 30, 2016, there was a $2.9 million net derivative loss recorded for derivative contracts for crude oil and natural gas as increased prices for crude oil and natural gas resulted in a reversal of previously recorded gains for open derivatives contracts. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For the nine months ended September 30, 2015, there was a $9.2 million net derivative gain recorded for derivative contracts for crude oil and natural gas.

Interest expense. Interest expense incurred was $81.3 million in the nine months ended September 30, 2016, up from $77.8 million for the same period in 2015. The increase was primarily attributable to the issuance of the Second Lien Term Loan in May 2015 with an aggregate principal of $300.0 million. Partially offsetting were decreases attributable to the Exchange Transaction. For the New Debt issued in the Exchange Transaction, undiscounted future cash flows (principal, PIK and cash interest) are recorded as the carrying value of the New Debt under ASC 470-60; therefore, no interest expense was recorded for the New Debt for the period of September 7, 2016 to September 30, 2016. In addition, interest expense was lower due to lower average borrowings on the revolving bank credit facility. During the nine months ended September 30, 2016 and 2015, $0.5 million and $6.0 million, respectively, of interest costs were capitalized related to unevaluated oil and natural gas properties. The decrease is primarily attributable to the sale of the Yellow Rose field in October 2015 and reclassification of certain unevaluated properties to the full cost pool during the nine months ended September 30, 2016 and the full year of 2015.

Gain on exchange of debt. A gain of $124.0 million was recorded related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as undiscounted future cash flows of the New Debt, plus the fair value of the common stock issued and deal transaction costs were less than the sum of the carrying value of the Unsecured Senior Notes exchanged combined with the funds received from the 1.5 Lien Term Loan issued. See Liquidity and Capital Resources in this Item for a table on the calculation of the gain.

Other (income) expense, net. Other expense (net) for the nine months ended September 2016 and 2015 was $1.2 million and $2.6 million, respectively. These were primarily due to write-off's of unamortized debt issuance costs. During the nine months ended September 30, 2016 and 2015, the borrowing base on the revolving bank credit facility was reduced. The reductions in the borrowing base resulted in proportional reductions of $1.4 million and $2.0 million, respectively, in the unamortized debt issuance costs related to the revolving bank credit facility. In addition, during the third quarter of 2015, a net loss on sale of assets of $1.0 million was recorded primarily related to the sale of computer equipment used for backup purposes.

Income tax benefit. Our income tax benefit for the nine months ended September 30, 2016 and 2015 was $44.4 million and $166.2 million, respectively, with the change attributable primarily to the deferred tax assets and the valuation allowance recorded for the respective periods. Our annualized effective tax rate for the nine months ended September 30, 2016 and 2015 was 14.3% for both periods, and differs from the federal statutory rate of 35% primarily due to the valuation allowances recorded for our deferred tax assets in both periods. During the nine months ended September 30, 2016 and 2015, we recorded valuation allowances of $63.1 million and $241.6 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

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 with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings.

A prolonged continuation of weak commodity prices relative to our cost of finding and producing new reserves, or the occurrence of one or a series of significant events substantially adversely impacting our liquidity, such as a demand for substantial additional financial assurances from BOEM or a final judgment for substantial monetary damages in our lawsuit with Apache, could result in our being unable to satisfy our future debt service obligations, meet other financial obligations and comply with the debt covenants governing our indebtedness. If such events were to occur in the future, we may seek relief under the U.S. Bankruptcy Code, which relief may include (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks.

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

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

During 2016, we engaged legal and financial advisors to assist the Board of Directors and our management team to evaluate the various alternatives available to us and executed the transaction described below:

Exchange Transaction. On September 7, 2016, we consummated a transaction whereby we exchanged approximately $710.2 million in aggregate principal amount, or 79%, of our Unsecured Senior Notes, due June 15, 2019 for: (i) $159.8 million in aggregate principal amount of 9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020; (ii) $142.0 million in aggregate principal of 8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021; and (iii) 60.4 million shares of our common stock (the "Debt Exchange"). The reduction in the debt principal from exchanging the Unsecured Senior Notes is presented in the following table (in thousands):

	Closing on September 7, 2016
8.50% Unsecured Senior Notes, due June 2019, exchanged - Principal	$ 710,171
Secured Debt Issued (principal):	
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020	159,763
8.50%/10.00% Third Lien PIK Toggle Notes due June 2021	142,031
Subtotal	301,794
Reduction of debt principle	$ 408,377

The table above does not reflect accounting adjustments under ASC 470-60 (Troubled Debt Restructuring).

At the same time on closing on the Debt Exchange, we closed on a $75.0 million, 11.00% 1.5 Lien Term Loan, due November 2019, with the largest holder of our Unsecured Senior Notes. We accounted for the Exchange Transaction as a Troubled Debt Restructuring under ASC 470-60. Under ASC 470-60, the carrying value of the newly issued Second Lien PIK Toggle Notes, Third Lien PIK Toggle Notes and 1.5 Lien Term Loan is measured using all future undiscounted payments (principal and interest); therefore, no interest expense was recorded for the New Debt in the Consolidated Statements of Operations during the three and nine month months ended September 30, 2016. Additionally, no interest expense related to the New Debt will be recorded in future periods as payments of interest on the New Debt will be recorded as a reduction in the carrying amount; thus, our reported interest expense will be significantly less than the contractual interest payments through the terms of the New Debt. Under ASC 470-60, future payments related to the New Debt will be reported in the financing section of the Statement of Cash Flows.

The following table presents all of our long-term debt, with September 30, 2016 being after the Exchange Transaction and June 30, 2016 and December 30, 2015 being prior to the Exchange Transaction (in thousands):

	September 30, 2016			June 30, 2016	December 31, 2015
	Principal	PIK Payable/ Interest Payable/ Other	Carrying Value	Principal/ Other*	Principal/ Other*
Revolving Bank Credit Facility, due November 2018	$—	$—	$—	$148,000	$—
11.00% 1.5 Lien Term Loan, due November 2019	75,000	26,393	101,393	—	—
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	159,763	64,142	223,905	—	—
8.50%/10.00% Third Lien PIK Toggle Notes, due June 2021	142,031	71,416	213,447	—	—
8.50% Unsecured Senior Notes, due June 2019	189,829	—	189,829	900,000	900,000
Subtotal	866,623	161,951	1,028,574	1,348,000	1,200,000
Debt premium, discount, issuance costs, net of amortization	—	(5,590)	(5,590)	(2,949)	(3,145)
Total long-term debt	866,623	156,361	1,022,984	1,345,051	1,196,855
Current maturities of long-term debt	—	8,763	8,763	—	—
Long term debt, less current maturities	$866,623	$147,598	$1,014,221	$1,345,051	$1,196,855

* Amounts also equal the carrying value as of these dates.

A gain of $124.0 million was recognized related to the Exchange Transaction. Under ASC 470-60, a gain was recognized as the sum of (i) the future undiscounted payments (principal and interest) related to the New Debt, (ii) the fair value of the common stock issued and (iii) deal transaction costs of $18.9 million was less than the sum of (iv) the carrying value of the Unsecured Senior Notes exchanged and (v) the funds received from the 1.5 Lien Term Loan. The 60,435,544 shares of common stock issued were valued at $1.76 per share, which was the closing price on September 7, 2016. Transaction costs related to the Exchange Transaction of approximately $2.8 million previously recorded as General and Administrative expense were reclassified and netted against the Gain on Debt Exchange. When such costs were previously recorded, the Exchange Transaction was dependent on approvals and actions by third parties including the approval of two-thirds of our shareholders.

The following table presents the calculation of the gain on exchange of debt (in thousands):

	Closing on September 7, 2016	
(i) Future Undiscounted Payments related to New Debt:		
9.00 % Second Lien Term Loan, due May 2020 - Principal		
Principal	$ 159,763	
PIK Payable	27,292	
Interest Payable	36,850	
9.00%/10.75% Second Lien PIK Toggle Notes, due May 2020:		
Principal	142,031	
PIK Payable	30,711	
Interest Payable	40,705	
11.00% 1.5 Lien Term Loan, due November 2019:		
Principal	75,000	
Interest Payable	26,393	
(ii) Fair value of common stock issued	106,367	
(iii) Exchange Transaction costs	18,895	
(A) Sub-Total of (i), (ii) and (iii) above		$ 664,007
(iv) Carrying value of 8.50% Unsecured Senior Notes, due June 2019, exchanged:		
Principal	710,171	
Unamortized debt issuance costs and premium	2,796	
(v) 11.00% 1.5 Lien Term Loan - funds received	75,000	
(B) Sub-Total of (iv) and (v) above		787,967
Gain on exchange of debt (A less B)		$ 123,960

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

For the Third Lien PIK Toggle Notes and the 1.5 Lien Term Loan, the maturity of both will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes are not extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. A total of $247.7 million would become due on February 28, 2019 if acceleration were to occur.

Credit Agreement and Other Long-Term Debt. In conjunction with the Exchange Transaction, amendments were executed for the Credit Agreement. The primary items related to the recent amendments are:

- Borrowing base revisions have been suspended until April 2017, (referred to as a bank holiday), at which time the borrowing base will be redetermined per the normal timeframe described below. The borrowing base was not changed and remains at $150.0 million.
- The First Lien Leverage Ratio limits were changed to 2.50 to 1.00 through June 30, 2017, and to 2.00 to 1.00 thereafter.
- 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 million if outstanding balances on the revolving bank credit agreement (including letters of credit) are greater than $5 million.
- The margins on amounts borrowed were increased. Borrowings primarily are executed as Eurodollar Loans, and the applicable margins range from 3.00% to 4.00%.
- The commitment fee was changed to 50 basis points for all levels of utilization.

Availability as of September 30, 2016 was $149.1 million. At September 30, 2016 and December 31, 2015, no amounts were outstanding and letters of credit were $0.9 million under our revolving bank credit facility. During the nine months ended September 30, 2016, the outstanding borrowings on the revolving bank credit facility ranged from zero to $340.0 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 (except as established by the bank holiday) and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The spring redetermination occurred in March 2016 and the next redetermination will occur in April 2017 due to the bank holiday. Subsequent to April 2017, the lenders and the Company have the option for an additional redetermination every year. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess is required to be repaid within 90 days in three equal monthly payments. Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists. The revolving bank credit facility is secured and is collateralized by substantially all of our oil and natural gas properties. The Credit Agreement terminates on November 8, 2018.

The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement and the other debt instruments as of September 30, 2016.

The recorded amounts of our long-term debt and the primary terms are disclosed in Financial Statements - Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q.

BOEM Matters. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. The significant and sustained decline in crude oil and natural gas prices, however, resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the regulations and then-current supplemental bonding procedures of the BOEM's NTL #2008-N07. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM under NTL #2008-N07. In February and March 2016, we received several orders from the BOEM ordering the Company to secure financial assurances in the form of additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, RUE and ROW. We have filed appeals with the IBLA regarding four of the BOEM orders - specifically the February order requiring the Company to post a total of $159.8 million in additional security and three March orders requiring $101.0 million in additional security. The IBLA, acknowledging that the BOEM and the Company were seeking to resolve the BOEM orders through settlement discussions, has agreed to stay the effectiveness of the orders. This is the third stay that we have received from the IBLA, and their latest stay extends the effectiveness to January 31, 2017. We submitted a proposal for a tailored plan of compliance in May of 2016 and have had ongoing discussions with the BOEM and its sister agency, the BSEE, in an effort to seek an acceptable resolution of the orders.

In July 2016, effective September 12, 2016, the BOEM issued NTL #2016-N01, related to obligations for decommissioning activities on the OCS, to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional security may be required for OCS leases, ROW and RUE. This NTL supersedes and replaces NTL #2008-N07. Among other things, the NTL eliminates the "waiver exemption" currently allowed by the BOEM, whereby lessees on the OCS meeting certain financial strength and reliability criteria are exempted from posting bonds or other acceptable financial assurances for such lessee's decommissioning obligations. Under the new NTL, qualifying operators may self-insure for an amount up to 10% of their tangible net worth. In addition, the NTL implements a phase-in period for establishing compliance with additional security obligations for certain properties, whereby lessees may seek compliance with its additional security requirements under a "tailored plan" that is approved by the BOEM and would require securing phased in compliance in three approximately equal installments during a one-year period from the date of the BOEM approval of the tailored plan. Additional security for sole liability properties (those leases, ROWs or RUEs where there are no co-lessees or other grant holders or prior interest holders who may be liable to the BOEM) may not be phased in.

In July 2016, the BOEM issued an implementation timeline with respect to NTL #2016-N01, setting forth a timeline for lessees to submit a self-insurance request, for the BOEM to send out proposal letters outlining required additional security, for the BOEM to send out the order letters, for lessees to submit a tailored plan and for lessees to provide additional security. Implementation of this new NTL could result in us having to obtain additional bonds or other financial assurances and having to post collateral to obtain such additional bonds or other financial assurances.

Since the new NTL went into effect in September 2016, we have received from the BOEM "self-insurance" letters confirming that we do not qualify to self-insure a portion of any additional financial assurance, as well as "proposal" letters outlining what additional security the BOEM proposes to require from us and other parties liable for lease, ROW, and RUE decommissioning obligations. We are reviewing these proposal letters for accuracy. We have also submitted a revised proposed tailored plan of compliance to the BOEM that we believe to be consistent with the revised regulations under NTL #2016-N01 and we remain hopeful that our negotiations with the BOEM will result in an acceptable tailored plan. If those negotiations do not result in an acceptable tailored plan and if we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

See "Risk Factors — We may be unable to provide the financial assurances demanded by the BOEM to cover our lease decommissioning obligations in the amounts and under the time periods required by the BOEM, either under the current rules or new rules that may be proposed. If extensions and modifications to the BOEM's current or future demands are needed and cannot be obtained, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases" under Part II, Item 1A of this Form 10-Q.

Surety Bond Collateral. Some of the sureties under our existing supplemental surety bonds have requested collateral from us, and may request additional collateral from us, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety's discretion.

The issuance of any additional surety bonds or other security to satisfy the BOEM orders, any 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 the creation of escrow accounts.

Cash Flow and Working Capital. Net cash used in operating activities for the nine months ended September 30, 2016 was $9.2 million and net cash provided by operating activities for the nine months ended September 30, 2015 was $134.8 million. Cash flows from operating activities, before changes in working capital and ARO, were $42.8 million for the nine months ended September 30, 2016, compared to $125.5 million generated in the comparable period. The reduction in cash flows was primarily due to lower realized prices for all our commodities - oil, NGLs and natural gas and lower production volumes, partially offset by lower operating expenses. Our combined average realized sales price per Boe decreased 21.5%, which lowered revenues $87.3 million (73.7% of the total change in revenues). Combined volumes on a Boe basis decreased 9.8%, which lowered revenues by $29.0 million. Partially offsetting were decreases in lease operating expenses of $24.9 million and lower G&A expenses of $11.7 million.

Other items affecting operating cash flows for the nine months ended September 30, 2016 were ARO settlements of $56.2 million, collateral deposits of $16.9 million, partially offset by changes in receivables, accounts payable and accrued liabilities of $20.3 million.

Net cash used in investing activities during the nine months ended September 30, 2016 and 2015 was $60.1 million and $259.5 million, respectively, which represents our investments in oil and gas properties and equipment. There were no acquisitions of significance during either period. Investments in oil and natural gas properties on an accrual basis in the nine months ended September 30, 2016 were $24.1 million compared to $192.8 million for the same period in 2015. The majority of expenditures during the nine months ended September 30, 2016 related to investments on the conventional shelf. In addition, adjustments from working capital changes associated with investing activities used net cash of $37.4 million in the nine months ended September 30, 2016 compared to net cash usage of $65.5 million for the same period in 2015. Both of these amounts represent cash expenditures in the year following the work, and accrual of the cost for accounting purposes occurred in the period the work was performed.

Net cash provided by financing activities for the nine months ended September 30, 2016 and 2015 was $57.2 million and $108.5 million, respectively. The net cash provided for the nine months ended September 30, 2016 was attributable to the 1.5 Lien Term Loan, partially offset by costs related to the Exchange Transaction. The net cash provided for the nine months ended September 30, 2015 was attributable to the issuance of the Second Lien Term Loan, partially offset by repayments on the revolving bank credit facility.

Derivative Financial Instruments. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of September 30, 2016, we had outstanding open derivatives for crude oil and natural gas. These derivatives provide downside protection against a portion of our remaining 2016 production and will provide cash inflows when crude oil or natural gas prices average below $40.00 per barrel and $2.25 per MMBtu, respectively, in a month. See Financial Statements - Note 4 - Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Insurance Claims and Insurance Coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which $161.2 million has been collected through September 30, 2016. In June 2014, the Fifth Circuit reversed a lower court’s ruling in holding that our Excess Policies cover removal-of-wreck and debris claims arising from Hurricane Ike, even though we exhausted the limits of our Energy Package with non-removal-of-wreck and debris claim. Several of the underwriters have not paid us amounts we claim are due under such Excess Policies in accordance with the Fifth Circuit ruling. We filed a lawsuit in September 2014 against certain underwriters for amounts owed, interest, attorney fees and damages. We subsequently received reimbursement from certain underwriters of the Excess Policies of approximately $10 million. We believe we are still owed additional reimbursement of removal-of-wreck costs of approximately $31 million, plus interest, attorney fees and damages, if any. See Financial Statements - Note 11 - Contingencies under Part I, Item 1 of this Form 10-Q for additional information.

We currently carry multiple layers of insurance coverage in our Energy Package 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. We carry named windstorm coverage of $150.0 million for a total loss only (“TLO”) on our Mahogany platform (Ship Shoal 349) and do not have named windstorm coverage on any other of our properties. The operational and named windstorm coverages described above are effective until June 1, 2017. Coverage for pollution causing a negative environmental impact is provided under the well control and named windstorm sections of the policy.

Our general and excess liability policies are effective until May 1, 2017 and provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE and we have insurance coverage of such amount.

Although we were able to renew our general and excess liability policies in May 2016, and our Energy Package in June 2016, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

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. The following table presents our capital expenditures on an accrual basis for exploration, development and other leasehold costs and acquisitions:

	Nine Months Ended September 30, 2016	2015
	(In thousands)	
Exploration (1)	$10,770	$47,699
Development (1)	10,744	130,444
Seismic, capitalized interest, and other	2,548	14,668
Acquisitions and investments in oil and gas property/equipment	$24,062	$192,811

(1) Reported geographically in the subsequent table.

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

	Nine Months Ended September 30, 2016	2015
	(In thousands)	
Conventional shelf	$17,234	$10,542
Deepwater	4,390	153,052
Deep shelf	(110)	215
Onshore	—	14,334
Exploration and development capital expenditures	$21,514	$178,143

Our capital expenditures for the nine months ended September 30, 2016 were financed by cash flow from issuance of debt, sales of properties, and cash on hand.

The following table presents our offshore wells drilled based on a completed basis:

	Nine Months Ended September 30, 2016		2015	
	Gross	Net	Gross	Net
Development wells - Productive	—	—	—	—

Exploration wells -	Productive	1	0.5	5	1.2
Total wells		1	0.5	5	1.2

There were no unproductive (dry holes) during either period presented. The Company drilled onshore wells during 2015, which were included with the sale of the Yellow Rose field in October 2015 and were excluded in the table above as the Company has sold, relinquished or let expire essentially all onshore leasehold interests.

Exploration Activities. During the first quarter of 2016, the Ewing Bank 954 A-8 exploration well, which is part of the Ewing Bank 910 field, was completed and began producing on March 1, 2016. During the third quarter of 2016, we resumed drilling on the A-18 well at Ship Shoal 349 ("Mahogany"), which had been suspended during 2015.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. We sold property interests during 2016, which provided $1.5 million in cash. As previously discussed, in 2015 we sold our interest in the Yellow Rose field for $370.9 million cash after adjustments, reduced related ARO for $6.9 million and transferred the obligation of other related liabilities of $1.1 million. See Financial Statements - Note 2 – Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

Capital Expenditure Budget for 2016. Our capital expenditures for 2016 are currently estimated at $60 million (on an accrual basis) and well below prior year levels due to the continued weak commodity prices. See the Overview section for additional information.

Income Taxes. During the nine months ended September 30, 2016, we made income tax payments of $0.3 million and received $7.8 million of refunds, which includes an income tax refund of $5.6 million related to an NOL claim for 2015 carried back to 2005 filed on Form 1139, Corporation Application for Tentative Refund. During the nine months ended September 30, 2015, we did not make any income tax payments nor receive any refunds of significance. For the remainder of 2016, we expect that a substantial portion of our income tax will be deferred and payments, if any, will be primarily related to state taxes.

As of September 30, 2016, we have recorded non-current income taxes receivable of $52.1 million. This net amount of our NOL claims for the years 2012, 2013 and 2014 were carried back to the years 2003, 2004, 2007, 2010 and 2011 filed on Form 1120X, U.S. Corporation Income Tax Return. These carryback claims are made pursuant to IRC Section 172(f), which permits certain platform dismantlement, well abandonment and site clearance costs to be carried back 10 years. The refund claims filed on Form 1120X will require a review by the Congressional Joint Committee on Taxation and are accordingly classified as non-current.

We have $181.9 million of Federal net operating loss carryforwards (tax basis) available to offset future federal taxable income in 2016 and forward. As a result of the tax gain realized on the Exchange Transaction, we anticipate the Federal net operating loss carryforward to be fully offset by the gain and accordingly, no carryovers will be available to 2017. We also have $33.9 million of alternative minimum tax credit carryforwards (tax basis) available to be utilized in 2016 and forward.

Dividends. During the nine months ended September 30, 2016 and the full year of 2015, we did not pay any dividends and a suspension of dividends remains in effect.

Asset Retirement Obligations. Each quarter, we review and revise our ARO estimates. Our ARO at September 30, 2016 and December 31, 2015 were $346.8 million and $378.3 million, respectively. Our estimate of ARO spending for the October 2016 to September 2017 time period is $90.2 million. As each of these estimates are 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 our Annual Report on Form 10-K for the year ended December 31, 2015, Item 1A, Risk Factors, for additional information.

Contractual Obligations. Updated information on certain contractual obligations is provided in Financial Statements – Note 3 – Asset Retirement Obligation, and Note 5 – Long-Term under Part I, Item 1 of this Form 10-Q. As of September 30, 2016, drilling rig commitments were approximately $5.3 million compared to $7.0 million as of December 31, 2015. The current drilling rig commitments relate primarily to demobilization obligations and two drilling rigs, one of which is being used for a plug and abandonment project. Except for scheduled utilization, other contractual obligations as of September 30, 2016 did not change materially from the disclosures in Management's Discussion and Analysis of Financial Condition and Results of Operations, of our Annual Report under Part II, Item 7 on Form 10-K for the year ended December 31, 2015.

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, 2015. 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 nine months ended September 30, 2016 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, 2015. 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, 2015.

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 and could have further impact on our business in the future. As of September 30, 2016, we had open derivative contracts related to a portion of estimated production for the remainder of 2016. 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 prices, but they also may limit future income from favorable price movements. See Financial Statements - Note 4 - Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of September 30, 2016, 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 rates for the LIBOR and the margin, which ranges from 3.00% to 4.00% depending on the amount outstanding. As of September 30, 2016, 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 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 September 30, 2016, 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 September 30, 2016, 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 11 – Contingencies, and Note 12 – Subsequent Events 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, 2015, 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 the continued weakness in 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, 2015 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, 2015, except as set forth below.

We may be unable to provide the financial assurances demanded by the BOEM to cover our lease decommissioning obligations in the amounts and under the time periods required by the BOEM, either under the current rules or new rules that may be proposed. If extensions and modifications to the BOEM's current or future demands are needed and cannot be obtained, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or post surety bonds or other acceptable financial assurances that such decommissioning obligations will be satisfied. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. The significant and sustained decline in crude oil and natural gas prices, however, resulted in the Company no longer meeting the relevant financial strength and reliability criteria for such exemptions set forth in the regulations and then-current bonding procedures of the BOEM's NTL #2008-N07. As a result, we were notified by the BOEM in 2015 that the Company was no longer eligible for any exemption from providing financial assurances to the BOEM under NTL #2008-N07.

In February and March 2016, we received several demands from the BOEM ordering the Company to secure financial assurances in the form of additional security in the aggregate of $260.8 million, with amounts specified with respect to certain designated leases, rights of use and easement and rights of way. We have filed appeals with the IBLA regarding four of the BOEM orders—specifically the February order requiring the Company to post a total of $159.8 million in additional security and three March orders requiring $101.0 million in additional security. The IBLA, acknowledging that the BOEM and the Company were seeking to resolve the BOEM orders through settlement discussions, stayed the effectiveness of the orders until June 30, 2016. Because settlement discussions were ongoing, the IBLA has agreed to stay the effectiveness of the orders until January 31, 2017. We continue to have discussions with the BOEM and its sister agency, the BSEE, in an effort to seek an acceptable resolution of the orders.

In July 2016, effective September 12, 2016, the BOEM issued NTL #2016-N01, related to obligations for decommissioning activities on the OCS, to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional security may be required for OCS leases, ROW and RUE. This NTL supersedes and replaces NTL #2008-N07. Among other things, the NTL eliminates the "waiver exemption" currently allowed by the BOEM, whereby lessees on the OCS meeting certain financial strength and reliability criteria are exempted from posting bonds or other acceptable financial assurances for such lessee's decommissioning obligations. Under the new NTL, qualifying operators may self-insure for an amount up to 10% of their tangible net worth. In addition, the NTL implements a phase-in period for establishing compliance with additional security obligations for certain properties, whereby lessees may seek compliance with its additional security requirements under a "tailored plan" that is approved by the BOEM and would require securing phased in compliance in three approximately equal installments during a one-year period from the date of the BOEM approval of the tailored plan. Additional security for sole liability properties (those leases, ROWs or RUEs where there are no co-lessees or other grant holders or prior interest holders who may be liable to the BOEM) may not be phased in.

On July 14, 2016, BOEM issued an implementation timeline with respect to NTL #2016-N01, setting forth a timeline for lessees to submit a self-insurance request, for BOEM to send out proposal letters outlining required additional security, for BOEM to send out the order letters, for lessees to submit a tailored plan and for lessees to provide additional security. Since the new NTL went into effect in September 2016, we have received from the BOEM "self-insurance" letters confirming that we do not qualify to self-insure a portion of any additional financial assurance, as well as "proposal" letters outlining what additional security the BOEM proposes to require from us and other parties liable for lease, ROW, and RUE decommissioning obligations. We are reviewing these proposal letters for accuracy. We have also submitted a revised proposal for a tailored plan to the BOEM that we believe to be consistent with the revised regulations under NTL #2016-N01. Implementation of this new NTL could result in us having to obtain additional bonds or other financial assurances and having to post collateral to obtain such additional bonds or other financial assurances. We believe our discussions with BOEM are consistent with a tailored arrangement under NTL #2016-N01 and we remain hopeful that our negotiations with the BOEM will result in an acceptable tailored plan with the BOEM. However, if those negotiations do not result in an acceptable tailored plan and if we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

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

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. As of September 30, 2016, we had $189.8 million of unsecured indebtedness and approximately $676.8 million of secured indebtedness outstanding (excluding $0.9 million of letters of credit and amounts included in the carrying value of certain debt for future PIK and cash interest payments). The components of our indebtedness are:

- $0.9 million of letters of credit;
- $75.0 million in aggregate principal amount of 1.5 Lien Term Loan;
- $300.0 million in aggregate principal amount of the Second Lien Term Loan;
- $159.8 million of Second Lien PIK Toggle Notes;
- $142.0 million of Third Lien PIK Toggle Notes; and
- $189.8 million in aggregate principal amount of the Unsecured Senior Notes.

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

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

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

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

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

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

We may not be able to extend, renew, refund, defease, discharge, replace or refinance our Unsecured Senior Notes by February 28, 2019.

For the Third Lien PIK Toggle Notes and the 1.5 Lien Term Loan, the maturity of both will accelerate to February 28, 2019 if the remaining Unsecured Senior Notes are not extended, renewed, refunded, defeased, discharged, replaced or refinanced by February 28, 2019. Assuming the PIK option is fully utilized for the Third Lien PIK Toggle Notes, the principal balance would grow and would be approximately $172.7 million as of February 28, 2019. For the 1.5 Lien Term Loan, no PIK option is available and the principal of $75.0 million would be unchanged as of February 28, 2019. Thus, a total of $247.7 million may become due on February 28, 2019. We may not have available funds to make these payments, which may cause us to be in default if amendments to the indentures cannot be obtained or resolved through other remedies. A default, if not waived, could result in acceleration of the debt outstanding under such agreement and in a default with respect to, and acceleration of, the debt outstanding under any other debt agreements. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to make all of the required payments or borrow sufficient funds to refinance such accelerated debt. Even if new financing were then available, it may not be on terms that are acceptable to us.

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

We are required to record a liability for the present value of our ARO to plug and abandon inactive nonproducing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or such requirements may be interpreted more restrictively, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. For example, because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future ARO could differ dramatically from what we may ultimately incur as a result of platform damage.

During 2015, the additional bonding requirements under the BOEM's NTL #2008-N07 have increased the costs of our operations and availability of such bonds has been decreasing rapidly due to the decreases in commodity prices. In addition, the demands received from the BOEM in February and March 2016 will increase our costs and impact our liquidity in the future. The BOEM's newly issued NTL #2016-N01, replacing the existing NTL #2008-N07 and effective as of September 2016, is likely to further increase such costs and decrease such bond availability. In addition, increased demand for salvage contractors and equipment could result in increased costs for plugging and abandonment operations. These items have, and may, further increase our costs and may impact our liquidity adversely.

If we default on our secured debt, the value of the collateral securing our secured debt may not be sufficient to ensure repayment of all of such debt.

As of September 30, 2016, we had secured debt outstanding of $839.7 million which includes the outstanding principal, PIK and accrued interest and certain letter of credit reimbursement obligations. If in the future we default on one or more issues or tranches of our secured debt, we cannot assure you that the proceeds from the sale of the collateral will be sufficient to repay all of our secured debt in full. In addition, we have certain rights to issue or incur additional secured debt, including up to $149.1 million as of September 30, 2016 available for borrowing on our revolving bank credit facility, that would be secured by additional liens on the collateral and an issuance or incurrence of such additional secured debt would dilute the value of the collateral securing our outstanding secured debt. If the proceeds of any sale of the collateral are not sufficient to repay all amounts due in respect of our secured debt, then claims against our remaining assets to repay any amounts still outstanding under our secured obligations would be unsecured and our ability to pay our other unsecured obligations and any distributions in respect of our capital stock would be significantly impaired.

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

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

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

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index.

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 November 3, 2016.

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 INDEX

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 25, 2006)
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))
4.1	First Supplemental Indenture, dated as of September 7, 2016, by and among W&T Offshore, Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.2	9.00% / 10.75% Senior Second Lien PIK Toggle Notes due 2020 Indenture, dated as of September 7, 2016, by and among W&T Offshore, Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee. (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.3	Form of 9.00% / 10.75% Senior Second Lien PIK Toggle Notes due 2020 (included in Exhibit 4.2). (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.4	8.50% / 10.00% Senior Third Lien PIK Toggle Notes due 2021 Indenture, dated as of September 7, 2016, by and among W&T Offshore, Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee. (Incorporated by reference to Exhibit 4.4 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.5	Form of 8.50% / 10.00% Senior Third Lien PIK Toggle Notes due 2021 (included in Exhibit 4.4). Incorporated by reference to Exhibit 4.4 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
4.6	Registration Rights Agreement, dated as of September 7, 2016, by and among W&T Offshore, Inc. and the initial holders named therein. (Incorporated by reference to Exhibit 4.6 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))

10.1	Form of Support Agreement, effective July 25, 2016, by and among W&T Offshore, Inc. and certain Supporting Noteholders. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 25, 2016 (File No. 001-32414))

Exhibit Number	Description
10.2	Fourth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of July 28, 2016, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 3, 2016 (File No. 001-32414))
10.3	Form of Amendment to Support Agreement by and among the Company and the Supporting Noteholders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 16, 2016 (File No. 001-32414))
10.4	Fifth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of August 25, 2016, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as administrative agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 31, 2016 (File No. 001-32414))
10.5	1.5 Lien Term Loan Credit Agreement, dated as of September 7, 2016, by and among W&T Offshore, Inc., Cortland Capital Market Services LLC, as Administrative Agent and 1.5 Lien Collateral Agent, and the various lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.6	Priority Confirmation Joinder, dated as of September 7, 2016, by and between Toronto Dominion (Texas) LLC, as Priority Lien Agent, Cortland Capital Market Services LLC, as Administrative Agent and 1.5 Lien Collateral Agent, and Morgan Stanley Senior Funding, Inc., as Second Lien Collateral Trustee. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.7	Priority Confirmation Joinder, dated as of September 7, 2016, by and between Toronto Dominion (Texas) LLC, as Priority Lien Agent, Wilmington Trust, National Association, as Second Lien Trustee, and Morgan Stanley Senior Funding, Inc., as Second Lien Collateral Trustee. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.8	Priority Confirmation Joinder, dated as of September 7, 2016, by and between Toronto Dominion (Texas) LLC, as Priority Lien Agent, Morgan Stanley Senior Funding, Inc., as Second Lien Collateral Trustee, and Wilmington Trust, National Association, as Third Lien Trustee and Third Lien Collateral Trustee. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K, filed September 13, 2016 (File No. 001-32414))
10.9 * **	Form of Executive Annual Incentive Agreement for Fiscal 2016.
10.10* **	Form of 2016 Executive Restricted Stock Unit Agreement
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.

Exhibit Number	Description
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.

** Management Contract or Compensatory Plan or Arrangement.

63