W&T OFFSHORE INC
Form 10-Q
November 06, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015

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 þ   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 þ   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	þ
Non-accelerated filer	¨	Smaller reporting company	¨

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

As of November 2, 2015, there were 76,010,554 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	September 30, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$7,463	$23,666
Receivables:		
Oil and natural gas sales	43,955	67,242
Joint interest and other	42,435	43,645
Total receivables	86,390	110,887
Deferred income taxes	4,328	11,662
Prepaid expenses and other assets	25,513	36,347
Total current assets	123,694	182,562
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $111,677 at September 30, 2015 and $109,824 at December 31, 2014 were excluded from amortization)	8,257,118	8,045,666
Furniture, fixtures and other	21,372	23,269
Total property and equipment	8,278,490	8,068,935
Less accumulated depreciation, depletion and amortization	6,838,075	5,575,078
Net property and equipment	1,440,415	2,493,857
Restricted deposits for asset retirement obligations	15,578	15,444
Other assets	20,284	17,244
Total assets	$1,599,971	$2,709,107
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$107,469	$194,109
Undistributed oil and natural gas proceeds	28,870	37,009
Asset retirement obligations	84,588	36,003
Accrued liabilities	39,171	17,377
Total current liabilities	260,098	284,498
Long-term debt, less current maturities	1,473,348	1,360,057
Asset retirement obligations, less current portion	315,038	354,565
Deferred income taxes	13,173	186,988
Other liabilities	14,065	13,691

Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at September 30, 2015 and December 31, 2014	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,879,727 issued and 76,010,554 outstanding at September 30, 2015; 78,768,588 issued and 75,899,415 outstanding at December 31, 2014	1	1
Additional paid-in capital	422,633	414,580
Retained earnings (deficit)	(874,218)	118,894
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity (deficit)	(475,751)	509,308
Total liabilities and shareholders' equity	$1,599,971	$2,709,107

See Notes to Condensed Consolidated Financial Statements.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands except per share data) (Unaudited)			
Revenues	$126,228	$234,521	$403,201	$752,031
Operating costs and expenses:				
Lease operating expenses	45,039	71,732	143,500	189,116
Production taxes	889	1,794	2,526	5,628
Gathering and transportation	3,572	4,115	13,189	13,396
Depreciation, depletion, amortization and accretion	97,329	128,671	326,138	380,213
Ceiling test write-down of oil and natural gas properties	441,688	—	954,850	—
General and administrative expenses	16,515	21,007	57,038	64,277
Derivative (gain) loss	(10,231)	(13,781)	(9,153)	6,790
Total costs and expenses	594,801	213,538	1,488,088	659,420
Operating income (loss)	(468,573)	20,983	(1,084,887)	92,611
Interest expense:				
Incurred	28,754	21,783	77,816	64,703
Capitalized	(2,203)	(2,191)	(6,010)	(6,422)
Other (income) expense, net	964	(197)	2,647	(205)
Income (loss) before income tax expense (benefit)	(496,088)	1,588	(1,159,340)	34,535
Income tax expense (benefit)	(18,520)	904	(166,228)	12,825
Net income (loss)	$(477,568)	$684	$(993,112)	$21,710
Basic and diluted earnings (loss) per common share	$(6.29)	$0.01	$(13.08)	$0.28
Dividends declared per common share	$—	$0.10	$—	$0.30

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY (DEFICIT)

	Common Stock Outstanding		Additional Paid-In	Retained Earnings	Treasury Stock		Total Shareholders' Equity
	Shares	Value	Capital	(Deficit)	Shares	Value	(Deficit)
	(In thousands)						
				(Unaudited)			
Balances at December 31, 2014	75,899	$ 1	$ 414,580	$ 118,894	2,869	$ (24,167)	$ 509,308
Share-based compensation	—	—	8,313	—	—	—	8,313
Other	112	—	(260)	—	—	—	(260)
Net loss	—	—	—	(993,112)	—	—	(993,112)
Balances at September 30, 2015	76,011	$ 1	$ 422,633	$ (874,218)	2,869	$ (24,167)	$ (475,751)

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2015	2014
	(In thousands) (Unaudited)	
Operating activities:		
Net income (loss)	$(993,112)	$21,710
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	326,138	380,213
Ceiling test write-down of oil and gas properties	954,850	—
Debt issuance costs write-off/amortization of debt items	2,862	537
Share-based compensation	8,313	11,398
Derivative (gain) loss	(9,153)	6,790
Cash receipts (payments) on derivative settlements	2,139	(18,543)
Deferred income taxes	(166,258)	12,825
Changes in operating assets and liabilities:		
Oil and natural gas receivables	23,287	(936)
Joint interest and other receivables	1,210	1,890
Income taxes	(289)	2,884
Prepaid expenses and other assets	16,692	21,228
Asset retirement obligation settlements	(25,515)	(42,011)
Accounts payable, accrued liabilities and other	(6,371)	21,793
Net cash provided by operating activities	134,793	419,778
Investing activities:		
Acquisition of property interest in oil and natural gas properties	—	(71,515)
Investment in oil and natural gas properties and equipment	(192,811)	(383,953)
Changes in operating assets and liabilities associated with investing activities	(65,463)	5,167
Purchases of furniture, fixtures and other	(1,185)	(2,181)
Net cash used in investing activities	(259,459)	(452,482)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	263,000	378,000
Repayments of long-term debt - revolving bank credit facility	(445,000)	(321,000)
Issuance of 9.00% Term Loan	297,000	—
Debt issuance costs	(6,591)	—
Dividends to shareholders	—	(22,695)
Other	54	(181)
Net cash provided by financing activities	108,463	34,124
Increase (decrease) in cash and cash equivalents	(16,203)	1,420
Cash and cash equivalents, beginning of period	23,666	15,800
Cash and cash equivalents, end of period	$7,463	$17,220

See Notes to Condensed Consolidated Financial Statements.

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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 focused primarily in the Gulf of Mexico. On October 15, 2015, a substantial amount of our interest in onshore acreage was sold, which is described in Note 12. 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”).

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, 2014.

Transactions between Entities under Common Control. The prior period financial information for the three and nine months ended September 30, 2014 presented in Note 13, Supplemental Guarantor Information, has been retrospectively adjusted due to transactions between entities under common control, as required under authoritative guidance.

Reclassifications. Certain reclassifications were made to the prior period’s financial statements to conform to the current presentation. In the Condensed Consolidated Statements of Cash flows, Net cash provided by operating activities was increased by $5.2 million and Net cash used in investing activities was increased by $5.2 million for the nine months ended September 30, 2014 to account for the changes in operating liabilities associated with investing activities.

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.

Ceiling Test Write-Down. Under the full cost method of accounting, we are required to periodically 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%; (ii) plus the cost of unproved oil and natural gas properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base; and

(iv) less related income tax effects. Estimated future net revenues used in the ceiling test for each period are based on current prices for each product, defined by the SEC as the unweighted average of first-day-of-the-month commodity prices over the prior twelve months for that period. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials.

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 2015 which are reported as a separate line in the Statements of Operations. The average price using the SEC required methodology at September 30, 2015 was $55.73 per barrel for West Texas Intermediate (“WTI”) crude oil and $3.06 per million British Thermal Unit (“MMBtu”) for Henry Hub natural gas before adjustments. For reference, the comparable prices at October 1, 2015 were $41.25 per barrel for crude oil and $2.48 per MMBtu for natural gas. 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 for the three and nine months ended September 30, 2015 of $441.7 million and $954.9 million, respectively. We did not record a ceiling test write-down during 2014.

Recent Events. The price we receive for our oil, natural gas liquids (“NGLs”) and natural gas production directly affects our revenues, profitability, cash flows, liquidity, access to capital and future rate of growth. The prices of these commodities began falling in the second half of 2014 and were significantly lower during the nine months ended September 30, 2015 compared to the last few years.

We have taken several steps to mitigate the effects of these lower prices including: (i) significantly reducing the 2015 capital budget from the previous year; (ii) suspending our drilling and completion activities at several locations; (iii) suspending the regular quarterly common stock dividend; (iv) implementing numerous cost reduction projects to reduce our operating costs and (v) on October 15, 2015, sold our interest in the Yellow Rose field. See Note 12 for additional information.

During 2015, we have entered into three Amendments to our Fifth Amended and Restated Credit Agreement (as amended, the “Credit Agreement”), which, among other things, changed or eliminated certain financial covenants and authorized the administrative agent under the Credit Agreement to enter into an Intercreditor Agreement among the Company and various lenders. We entered into a second lien term loan (the “9.00% Term Loan”) in May 2015, with a principal amount of $300.0 million, maturing on May 15, 2020. In October 2015, the borrowing base of the revolving bank credit facility under the Credit Agreement was adjusted for the sale of our interest in the Yellow Rose field and was also redetermined. The borrowing base is set at $350.0 million effective October 30, 2015. We used a portion of the proceeds of the sale of our interest in the Yellow Rose field to repay all outstanding borrowings under the revolving bank credit facility, while the remaining balance of approximately $100.0 million was added to available cash. See Notes 5 and 12 for additional information.

We have assessed our financial condition, the current capital markets and options given different scenarios of future commodity prices and believe we will have adequate liquidity to fund our operations through September 30, 2016. However, we cannot predict how an extended period of commodity prices at existing levels or a significant reduction in our borrowing base will affect our operations and liquidity levels.

Recent Accounting Developments. In April 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2015-03 (“ASU 2015-03”), Interest – Imputation of Interest (Subtopic 835-30), Simplifying the Presentation of Debt Issuance Costs. The guidance seeks to simplify the presentation of debt issuance costs. The amendment would require debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of liability, consistent with debt discounts or premiums. The guidance was further clarified to state that debt issuance costs related to credit facilities could be reported as an asset regardless of the balance outstanding. The recognition and measurement guidance for debt issuance costs would not be affected by the amendment. ASU 2015-03 is effective in 2016 and is to be applied on a retrospective basis. Early adoption is permitted. We do not expect the revised guidance to materially affect our balance sheets as amounts will be reclassified from long-term assets to partial offsets of long-term debt. The revised guidance will not affect the statements of operations or the statements of cash flows.

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 May 2014, the FASB issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), Summary and Amendments that Create Revenue from Contracts and Customers (Topic 606). ASU 2014-09 amends and replaces current revenue recognition requirements, including most industry-specific guidance. The revised guidance establishes a five step approach to be utilized in determining when, and if, revenue should be recognized. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. Upon 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 determined 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.

2. Acquisitions and Divestitures

2015 Divestiture

See Note 12 for information on a divestiture occurring subsequent to September 30, 2015.

2014 Acquisitions

Fairway

On September 15, 2014, the Parent Company entered into an asset purchase agreement with a third party to increase its ownership interest from 64.3% to 100% in the Mobile Bay blocks 113 and 132 (the "Fairway Field") and the associated Yellowhammer gas processing plant (collectively, "Fairway"). The Fairway Field is located in the state waters of Alabama and the Yellowhammer gas processing plant is located in the state of Alabama. The effective date of the transaction was July 1, 2014. The transaction included customary adjustments for the effective date, certain closing adjustments and our assumption of the related ARO. A net purchase price increase of $1.3 million for customary final closing adjustments was recorded in 2015. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

The following table presents the purchase price allocation, including adjustments, for the increased ownership interest in Fairway (in thousands):

Cash consideration:	
Evaluated properties including equipment	$18,693
Non-cash consideration:	
Asset retirement obligations - non-current	6,124
Total consideration	$24,817

The acquisition was recorded at fair value, which was determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs were: (i) analysis of comparable transactions obtained from various third-parties, (ii) estimates of ultimate recoveries of reserves and (iii) estimates of discounted cash flows based on estimated reserve quantities, reserve categories, timing of production, costs to produce and develop reserves, future prices, ARO and discount rates. The estimates and assumptions were determined by management and third-parties. The fair value is based on subjective estimates and assumptions, which are inherently imprecise, and the actual realized values could vary significantly from these estimates. No goodwill was recorded in connection with this acquisition of an additional working interest in Fairway.

Woodside Properties

On May 20, 2014, Energy VI entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Woodside Energy (USA) Inc. ("Woodside"). The properties acquired from Woodside (the "Woodside Properties") consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater lease blocks. All of the Woodside Properties are located in the Gulf of Mexico. The effective date of the transaction was November 1, 2013. The transaction included customary adjustments for the effective date, certain closing adjustments and our assumption of the related ARO. A net purchase price increase of $0.2 million for customary final closing adjustments was recorded in 2015. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

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

The following table presents the purchase price allocation, including adjustments, for the acquisition of the Woodside Properties (in thousands):

Cash consideration:	
Evaluated properties including equipment	$52,347
Unevaluated properties	2,660
Sub-total cash consideration	55,007
Non-cash consideration:	
Asset retirement obligations - current	782
Asset retirement obligations - non-current	10,543
Sub-total non-cash consideration	11,325
Total consideration	$66,332

The acquisition was recorded at fair value, which was determined by applying the market and income approaches using Level 3 inputs. The Level 3 inputs were: (i) analysis of comparable transactions obtained from various third-parties, (ii) estimates of ultimate recoveries of reserves and (iii) estimates of discounted cash flows based on estimated reserve quantities, reserve categories, timing of production, costs to produce and develop reserves, future prices, ARO and discount rates. The estimates and assumptions were determined by management and third-parties. The fair value is based on subjective estimates and assumptions, which are inherently imprecise, and the actual realized values could vary significantly from these estimates. No goodwill was recorded in connection with the Woodside Properties acquisition.

2014 Acquisitions — Revenues, Net Income and Pro Forma Financial Information

The increase in working interest ownership for Fairway was not included in our consolidated results until the property transfer date, which occurred in September 2014 and the incremental revenue and operating expenses were immaterial for the three and nine month periods ended September 30, 2015. Unaudited pro forma information showing the effect of the acquisition of an additional Fairway working interest is not presented as the pro forma information is not materially different from the reported results presented for the three and nine month periods ended September 30, 2014.

The Woodside Properties were not included in our consolidated results until the property transfer date, which occurred in May 2014. For the three months ended September 30, 2015, the Woodside Properties accounted for $5.8 million of revenues, $2.4 million of direct operating expenses, $3.4 million of depreciation, depletion, amortization and accretion (“DD&A”) and no income tax expense, resulting in less than $0.1 million of net income. For the nine months ended September 30, 2015, the Woodside Properties accounted for $19.2 million of revenues, $7.5 million of direct operating expenses, $11.4 million of DD&A and $0.1 million of income tax expense, resulting in $0.2 million of net income. The net income attributable to the Woodside Properties does not reflect certain expenses, such as general and administrative expenses (“G&A”) and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Woodside Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

In accordance with the applicable accounting guidance, we have included herein certain unaudited pro forma financial information giving pro forma effect to the acquisition of the Woodside Properties computed as if the acquisition had been completed on January 1, 2013. The financial information was derived from W&T's audited historical consolidated financial statements for annual periods, W&T's unaudited historical condensed consolidated financial statements for interim periods, and the Woodside Properties' unaudited historical financial statements for the annual and interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Woodside Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2013. Had we owned the Woodside Properties during the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Woodside; the realized sales prices for oil, NGLs and natural gas may have been different; and the costs of operating the Woodside Properties may have been different.

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

The following table presents a summary of our pro forma financial information giving pro forma effect to the Woodside Properties acquisition (in thousands, except earnings per share):

	(unaudited) Nine Months Ended September 30, 2014
Revenue	$ 774,918
Net income	27,803
Basic and diluted earnings per common share	0.36

For the pro forma financial information, certain information was derived from our financial records, Woodside's financial records and certain information was estimated. Pro forma financial information for the three month period ended September 30, 2014 is not presented as there were no material differences from reported results.

The following table presents incremental items included in the pro forma information reported above for the Woodside Properties (in thousands):

	(unaudited) Nine Months Ended September 30, 2014 (a)
Revenues (b)	$ 22,887
Direct operating expenses (b)	4,417
DD&A (c)	8,385
G&A (d)	400
Interest expense (e)	330
Capitalized interest (f)	(19)
Income tax expense (g)	3,281

The sources of information and significant assumptions are described below:

(a) The adjustments for the period presented are from the beginning of the period to May 20, 2014.
(b) Revenues and direct operating expenses for the Woodside Properties were derived from the historical financial records of Woodside.

(c) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Woodside Properties' costs, reserves and production into our full cost pool in order to compute such amounts. The purchase price allocated to unevaluated properties for oil and natural gas interests was excluded from the DD&A expense estimation. ARO was estimated by W&T management.

(d) Consists of estimated incremental insurance costs related to the Woodside Properties.

(e) The Woodside Properties acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $55.0 million, which equates to the cash component of the acquisition purchase price, and an interest rate of 1.8%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.

(f) The change to capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. The negative amount represents a decrease to net expenses.

(g) Income tax expense was computed using the 35% federal statutory rate.

The pro forma adjustments do not include adjustments related to any other acquisitions or divestitures. As the acquisition occurred in the second quarter of 2014, pro forma financial information for the three months ended September 30, 2014 is not presented as there would be no differences from reported results.

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, 2014	$390,568
Liabilities settled	(25,515)
Accretion of discount	15,883
Disposition of properties	(965)
Liabilities incurred	7,615
Revisions of estimated liabilities (1)	12,040
Balance, September 30, 2015	399,626
Less current portion	84,588
Long-term	$315,038

(1) Revisions were primarily attributable to increases in scope of work, additional time to complete the work and from non-operated properties.

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.

Commodity Derivatives

During 2015, we entered into crude oil and natural gas derivative contracts for a portion of our anticipated future production. Some of the commodity derivative contracts are known as “three-way collars” consisting of a purchased put option, a sold call option and a purchased call option, each at varying strike prices. The strike prices of the contracts were set so that the contracts were premium neutral (“costless”), which means no net premium was paid to or received from a counterparty. The three-way collar contracts are structured to provide price risk protection if the commodity price falls below the strike price of the put option and provides us the opportunity to benefit if the commodity price rises above the strike price of the purchased call option. 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. In addition, we entered into oil derivative contracts known as “two-way”, “costless” collars, which consist of a purchased put option and a sold call option. These two-way collars provide price risk protection if crude oil prices fall below certain levels, but 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 New York Mercantile Exchange (“NYMEX”). The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX.

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

As of December 31, 2014, we did not have any open derivative contracts. During 2014, we used crude oil swap contracts and have used various derivative instruments in prior years to manage our exposure to commodity price risk from sales of our oil and natural gas. While these contracts were intended to reduce the effects of price volatility, they may have limited incremental income from favorable price movements.

As of September 30, 2015, our open commodity derivative contracts were as follows:

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

Termination Period	Notional Quantity (Bbls/day) (1)	Notional Quantity (Bbls) (1)	Weighted Average Contract Price Put Option (Bought)	Call Option (Sold)	Call Option (Bought)
2015: 4th Quarter	6,000	552,000	$50.00	$60.00	$ 62.30

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

Termination Period	Notional Quantity (Bbls/day) (1)	Notional Quantity (Bbls) (1)	Weighted Average Contract Price Put Option (Bought)	Call Option (Sold)
2016: 1st Quarter	5,000	455,000	$40.00	$81.47
2nd Quarter	5,000	455,000	40.00	81.47
3rd Quarter	5,000	460,000	40.00	81.47
4th Quarter	5,000	460,000	40.00	81.47
		1,830,000	40.00	81.47

Natural Gas: Three-way collars, Priced off Henry Hub (NYMEX) (1)

Termination Period	Notional Quantity (MMBTUs/day) (1)	Notional Quantity (MMBTUs) (1)	Weighted Average Contract Price Put Option (Bought)	Call Option (Sold)	Call Option (Bought)
2015: 4th Quarter (2)	30,000	1,830,000	$2.25	$ 3.25	$ 3.51

2016:	1st Quarter	40,000	3,640,000	2.25	3.50	3.77
	2nd Quarter	40,000	3,640,000	2.25	3.50	3.77
	3rd Quarter	40,000	3,680,000	2.25	3.50	3.77
	4th Quarter	40,000	3,680,000	2.25	3.50	3.77
			16,470,000	2.25	3.47	3.74

(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 2015 production were priced and closed in September 2015 and are not included in the above table as these were not open derivative contracts as of September 30, 2015.

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, 2015	December 31, 2014
Prepaid and other assets (current)	$ 5,970	$ —
Other assets (noncurrent)	1,044	—

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,	
	2015	2014	2015	2014
Derivative (gain) loss	$(10,231)	$(13,781)	$(9,153)	$6,790

Cash receipts (payments), 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,	
	2015	2014
Cash receipts (payments) on derivative settlements, net	$2,139	$(18,543)

Offsetting Commodity Derivatives

During 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. For the open derivative contracts as of September 30, 2015, there would have been no difference if the contracts were presented on net basis. There were no open derivative contracts as of December 31, 2014.

5. Long-Term Debt

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

	September 30, 2015	December 31, 2014
8.50% Senior Notes	$900,000	$900,000
Debt premiums, net of amortization	11,161	13,057
9.00% Term Loan	300,000	—
Debt discounts, net of amortization	(2,813)	—
Revolving bank credit facility	265,000	447,000
Total long-term debt	1,473,348	1,360,057
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$1,473,348	$1,360,057

At September 30, 2015 and December 31, 2014, our outstanding senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the "8.50% Senior Notes"), were classified as long-term at their carrying value. Interest on the 8.50% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the 8.50% Senior Notes is 8.4%, which includes amortization of debt issuance costs and premiums. The debt premiums, net of amortization, are related to the 8.50% Senior Notes. We are subject to various financial and other covenants under the indenture governing the 8.50% Senior Notes, and we were in compliance with those covenants as of September 30, 2015.

In May 2015, we entered into the 9.00% Term Loan, which has a principal of $300.0 million, bears an annual interest rate of 9.00%, was issued at a 1% discount to par and matures on May 15, 2020. The 9.00% Term Loan is secured by a second priority lien covering our oil and gas properties to the extent such properties secure first priority liens granted to secure indebtedness under our Credit Agreement. Interest on the 9.00% Term Loan is payable in arrears semi-annually on May 15 and November 15. The estimated annual effective interest rate on the 9.00% Term Loan is 9.7%, which includes amortization of debt issuance costs and discounts. The net proceeds were used to repay a portion of the outstanding borrowings incurred under our revolving bank credit facility governed by the Credit Agreement. An entity controlled by the Company's Chairman and Chief Executive Officer participated in the 9.00% Term Loan for a $5.0 million principal commitment on the same terms as the other lenders. We are subject to various covenants under the terms governing the 9.00% 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, 2015.

Our revolving bank credit facility governed by the Credit Agreement matures on November 8, 2018. Borrowings under our revolving bank credit facility are secured by our oil and natural gas properties. Availability under such facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria.

At both September 30, 2015 and December 31, 2014, we had $0.9 million of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 3.3% for the nine months ended September 30, 2015 for average daily borrowings 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 September 30, 2015, our borrowing base was $500.0 million and our borrowing availability was $234.1 million. See Note 12 for the results of the semi-annual redetermination and an amendment to the Credit Agreement subsequent to September 30, 2015.

Through September 30, 2015, we have entered into two amendments to the Credit Agreement. Following is a summary of the primary terms of the amendments:

- The applicable margin applied to borrowings under the Credit Agreement was increased by 50 basis points (0.5%) on an annual basis. The margins on London Interbank Offered Rate ("LIBOR") based borrowings range from 2.25% to 3.25% and the margins on alternate base rate borrowings range from 1.25% to 2.25%.

- The Amendments permit us to incur additional unsecured indebtedness, or incur additional indebtedness which is subordinate in security compared to the indebtedness under the Credit Agreement, provided that, (A) no event of default has occurred or would result from such incurrence, (B) the Company is in compliance with its financial ratios after giving pro forma effect to the incurrence of the additional indebtedness, (C) such additional indebtedness matures at least six months after the maturity date of the Credit Agreement, and (D) such additional indebtedness is not subject to covenants and events of default that are, taken as a whole, materially more onerous than those provided for in the Credit Agreement.
- Upon the incurrence of additional unsecured indebtedness, or the incurrence of additional indebtedness which is subordinate in security compared to the indebtedness under the Credit Agreement, the borrowing base will be reduced by $0.33 for each dollar of additional indebtedness until the borrowing base is redetermined. After giving effect to the issuance of the 9.00% Term Loan and the resulting reduction in the borrowing base, the borrowing base was adjusted to $500.0 million.
- We are restricted on making distributions or repurchasing the existing 8.50% Senior Notes, the 9.00% Term Loan or other permitted indebtedness (i) until June 30, 2016, (ii) if an event of default is continuing or would result from such distribution or (iii) if a borrowing base deficiency is continuing or would result therefrom; provided that the restriction in clause (i) of this sentence does not apply to (A) scheduled payments of interest, principal or redemptions on the Company's existing 8.50% Senior Notes, the 9.00% Term Loan or other permitted additional debt and (B) the redemption or repurchase by the Company of its outstanding indebtedness in an aggregate principal amount equal to the aggregate principal amount of any new indebtedness, provided that any such new notes are not subject to covenants and events of default that are, taken as a whole, materially more restrictive on the Company.
- The financial covenants, with definitions of capitalized terms contained in the Credit Agreement, were set as follows:

a) The maximum Leverage Ratio was suspended for the first quarter of 2016; then is limited to 5.00:1.00 for the second quarter of 2016; 4.50:1.00 for the third quarter of 2016; and 4.00:1.00 thereafter.
b) The minimum Current Ratio is 0.75:1.00 effective for the first quarter of 2015 through the fourth quarter of 2015; and 1.00:1.00 thereafter.
c) The maximum First Lien Leverage Ratio is 2.50:1.00 effective for the first quarter of 2015 and thereafter.
d) The maximum Secured Debt Leverage Ratio is 3.50:1.00 effective for the first quarter of 2015 and thereafter.
e) The minimum Interest Coverage Ratio is 2.20:1.00 effective for the first quarter of 2015 and thereafter.

- The mortgaged collateral requirement was increased from 80% to 90% of the total value of both the (i) total oil and gas reserves and (ii) the proved developed producing reserves.
- We are required to maintain minimum derivative positions of 25% of estimated oil and natural gas production for the second half of 2015 and 35% of estimated oil and natural gas production for 2016.
- The amendment authorized the Administrative Agent under the Credit Agreement governing our revolving credit facility to enter into an Intercreditor Agreement with the lenders under the 9.00% Term Loan, which established the relationship and the priority of the liens securing the revolving bank credit facility and the 9.00% Term Loan.

The foregoing description of the Credit Agreement does not purport to be complete and is qualified in its entirety by reference to the agreement.

During the second quarter of 2015, the borrowing base on the revolving bank credit facility was reduced after the semi-annual redetermination and further reduced in conjunction with the issuance of the 9.00% Term Loan pursuant to the terms of the Credit Agreement. The reductions in the borrowing base resulted in proportional reductions in the unamortized debt issuance costs of $2.0 million related to the Credit Agreement, which is recorded within the line Other (income) and expense, net on the Statements of Operations.

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Under the Credit Agreement, we are subject to various financial covenants, as listed above, which are calculated as of the last day of each fiscal quarter. We were in compliance with all applicable covenants of the Credit Agreement as of September 30, 2015.

See Note 12 for information on the third amendment and changes to the borrowing base subsequent to September 30, 2015.

For information about fair value measurements for our 8.50% Senior Notes, 9.00% Term Loan and revolving bank credit facility, 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 values of our 8.50% Senior Notes and 9.00% Term Loan were based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates.

The following table presents the fair value of our derivatives and long-term debt, as reported in the Condensed Consolidated Balance Sheets (in thousands):

		September 30, 2015		December 31, 2014
	Hierarchy	Assets	Liabilities	Liabilities
Derivatives	Level 2	$7,014	$—	$—
8.50% Senior Notes (1)	Level 2	—	400,500	594,000
9.00% Term Loan (1)	Level 2	—	259,500	—
Revolving bank credit facility (1)	Level 2	—	265,000	447,000

(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

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. As allowed by the Plan, during 2014 and in 2013, the Company granted restricted stock units ("RSUs") to certain of its employees. During the nine months ended September 30, 2015, no RSUs were granted. 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 achievement 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 based on the Company and the employee achieving certain pre-defined performance criteria.

During 2014, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items ("Adjusted EBITDA") for 2014 and (ii) Adjusted EBITDA as a percent of total revenues ("Adjusted EBITDA Margin") for 2014. For 2014, the Company was above target for Adjusted EBITDA and was slightly below target for Adjusted EBITDA Margin.

During 2013, RSUs granted were also subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2013; (ii) Adjusted EBITDA Margin for 2013; and (iii) the Company's total shareholder return ("TSR") ranking against peer companies' TSR for 2013, 2014 and January 1, 2015 to October 31, 2015. TSR is determined based upon the change in the entity's stock price plus dividends for the applicable performance period. For 2013, the Company exceeded the target for Adjusted EBITDA and was approximately at target for 2013 Adjusted EBITDA Margin. For 2014 and 2013, the Company was below target for the TSR rankings for each period.

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All RSUs granted to date are subject to employment-based criteria and vesting occurs in December of the second year after the grant. For example, the RSUs granted during 2013 will vest in December 2015 to eligible employees assuming the requisite performance goals and employment-based criteria are also satisfied.

The 2014 annual incentive award for the Chief Executive Officer ("CEO") was settled in shares of common stock based on a pre-determined price of $14.66 per share, pursuant to the terms of his award. In March 2015, after reductions for employee payroll and withholding taxes, the net amount of the CEO's 2014 award resulted in 37,316 shares of common stock issued to the CEO. The 2013 annual incentive award for the CEO was settled in shares of common stock based at the price of $14.84, which was the Company's closing price the day prior to the settlement date. In March 2014, after reductions for employee payroll and withholding taxes, the net amount of the CEO's 2013 award resulted in 42,547 shares of common stock issued to the CEO. The CEO awards for both years were 100% performance based and were subject to pre-defined performance measures and employment-based criteria, which were the same pre-defined performance measures and employment-based criteria established for the other eligible Company employees, and were subject to approval of the Compensation Committee.

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 2015, 2014 and 2013. The Restricted Shares are subject to service conditions and vesting occurs at the end of specified service periods.

At September 30, 2015, there were 4,735,483 shares of common stock available for issuance in satisfaction of awards under the Plan and 444,024 shares of common stock available for issuance in satisfaction of awards under the Director Compensation Plan. The shares available for both plans are reduced when Restricted Shares or shares of common stock are granted. RSUs reduce the shares available in the Plan when the RSUs are settled in shares of common stock, net of withholding tax. Although the Company has the option to settle RSUs in stock or cash at vesting, only common stock has been used to settle vested RSUs to date.

We recognize compensation cost for share-based payments to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that are expected to actually vest.

Awards Based on Restricted Stock to Non-Employee Directors. As of September 30, 2015, all of the unvested shares of Restricted Shares outstanding were issued to the non-employee directors. Restricted Shares are subject to forfeiture until vested and 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. The fair value of Restricted Shares was estimated by using the Company's closing price on the grant date.

A summary of activity in 2015 related to Restricted Shares awarded to non-employee directors is as follows:

	Restricted Shares	
		Weighted Average

	Shares	Grant Date Fair Value Per Share
Nonvested, December 31, 2014	43,210	$ 16.20
Granted	56,540	6.19
Vested	(21,520)	16.26
Nonvested, September 30, 2015	78,230	8.95

Subject to the satisfaction of service conditions, the outstanding Restricted Shares issued to the non-employee directors as of September 30, 2015 are expected to vest as follows:

	Restricted Shares
2016	34,265
2017	25,115
2018	18,850
Total	78,230

The grant date fair values of Restricted Shares awarded during the nine months ended September 30, 2015 and the nine months ended September 30, 2014 was $0.3 million for both periods. The fair values of Restricted Shares that vested during the nine months ended September 30, 2015 and the nine months ended September 30, 2014 were $0.1 million and $0.3 million, respectively.

Awards Based on Restricted Stock Units. As of September 30, 2015, the Company had outstanding RSUs issued to certain employees. As described above, the RSUs granted during 2014 and 2013 were 100% performance based and were subject to pre-defined performance measures and employment-based criteria. A portion of the RSUs granted during 2013 remain subject to the performance measure of TSR for the defined period in 2015; therefore, the number of RSUs may be adjusted upon determination of the performance. The RSUs subject to performance measurement which has not yet been determined are disclosed in the table below for RSUs potentially eligible to vest.

The fair value for the RSUs granted during 2014 was determined using the Company's closing price on the grant date as the performance measures were all Company-specific performance measures comprised of Adjusted EBITDA and Adjusted EBITDA Margin. The fair value for the 2013 RSUs was determined separately for the components related to the TSR targets and the Company specific performance measures (Adjusted EBITDA and Adjusted EBITDA Margin). The fair value for the 2013 RSUs component related to TSR targets was determined by using a Monte Carlo simulation probabilistic model. The inputs used in the probabilistic model for the Company and the peer companies were: average closing stock prices during January 2013; risk-free interest rates using the LIBOR ranging from 0.27% to 0.91% over the service period; expected volatilities ranging from 30% to 63%; expected dividend yields ranging from 0.0% to 3.1%; and correlation factors ranging from a negative 84% to a positive 95%. The expected volatilities, expected dividends and correlation factors were developed using historical data. The fair value of all other 2013 RSUs components was determined using the Company's closing price on the grant date.

All RSUs awarded are subject to forfeiture until vested and cannot be sold, transferred or otherwise disposed of during the restricted period. Dividend equivalents are earned at the same rate as dividends paid on our common stock after achieving the specified performance requirement for that component of the RSUs.

A summary of activity in 2015 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2014	1,977,335	$ 15.29
Vested	(23,500)	14.68
Forfeited	(114,900)	15.18
Nonvested, September 30, 2015	1,838,935	15.30

All of the outstanding RSUs are subject to the satisfaction of service conditions and a portion of the outstanding RSUs are also subject to pre-defined performance measurements. The RSUs outstanding as of September 30, 2015 potentially eligible to vest are listed in the table below:

	Restricted Stock Units
2015 - subject to service requirements	689,075
2015 - subject to service and other requirements (1)	84,855
2016 - subject to service requirements	1,065,005
Total	1,838,935

(1) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 200% of amounts granted.

The grant date fair value of RSUs granted during the nine months ended September 30, 2014 was $20.0 million. The fair value of RSUs that vested during the nine months ended September 30, 2015 and the nine months ended September 30, 2014 was $0.1 million for both periods.

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Share-Based Compensation. 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,	
	2015	2014	2015	2014
Share-based compensation expense from:				
Restricted stock	$87	$93	$270	$276
Restricted stock units	2,518	3,658	8,137	9,819
Common shares	—	3	(94)	1,303
Total	$2,605	$3,754	$8,313	$11,398
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$912	$1,314	$2,910	$3,989

Unrecognized Share-Based Compensation. As of September 30, 2015, unrecognized share-based compensation expense related to our awards of Restricted Shares and RSUs was $0.6 million and $8.1 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2018 for Restricted Shares and November 2016 for RSUs.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees and payable in cash. (In the case of the award to the CEO, the awards for 2014 and 2013 were paid in shares of common stock as described above.) 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 the nine months ended September 30, 2015, the Company issued cash-based incentive awards for 2015 that, in addition to being performance-based awards related to 2015 criteria, the payment of such awards is contingent on the Company achieving the following financial condition on or before December 31, 2017: 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 does not expect to achieve this financial condition by December 31, 2015, no amount was recognized related to the 2015 awards during the nine months ended September 30, 2015. Amounts recorded during the nine months ended September 30, 2015 relate to the 2014 cash-based awards, for which costs were recognized from the award date through February 2015 (the service period), and adjustments were recorded to true up previous estimates to actual payments.

Share-Based Compensation and Cash-Based Incentive Compensation Expense. A summary of incentive compensation expense is as follows (in thousands):

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Share-based compensation included in:				
General and administrative expenses	$2,605	$3,754	$8,313	$11,398
Cash-based incentive compensation included in:				
Lease operating expense	—	586	364	2,363
General and administrative expenses (1)	—	2,724	(233)	6,038
Total charged to operating income	$2,605	$7,064	$8,444	$19,799

(1) Adjustments to true up estimates to actual payments resulted in net credit balances to expense for the nine months ended September 30, 2015.

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8. Income Taxes

Our income tax benefit for the three and nine months ended September 30, 2015 was $18.5 million and $166.2 million, respectively. Our effective tax rate for the three and nine months ended September 30, 2015 was 3.7% and 14.3%, respectively. Both of these percentages differ from the federal statutory rate of 35.0% primarily due to recording a valuation allowance for our deferred tax assets. Income tax expense for the three and nine months ended September 30, 2014 was $0.9 million and $12.8 million, respectively. Our effective tax rate for the three months ended September 30, 2014 was not meaningful due to adjustments for a revised estimated effective rate computed on a year-to-date basis. Our effective tax rate for the nine months ended September 30, 2014 was 37.1%, and differed from the federal statutory rate primarily as a result of state income taxes and other permanent items.

During the three and nine months ended September 30, 2015, we recorded a valuation allowance of $156.2 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. Additionally, as of September 30, 2015 and December 31, 2014, we had a valuation allowance related to Louisiana state net operating losses of $4.3 million for both periods. The tax years 2012 through 2014 remain open to examination for Federal purposes. The tax years from 2011 through 2014 remain open to examination by some of the state tax jurisdictions to which we are subject.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the nine months ended September 30, 2015 and 2014, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit.

9. Earnings Per Share

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

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net income (loss)	$(477,568)	$684	$(993,112)	$21,710
Less portion allocated to nonvested shares	—	70	—	208
Net income (loss) allocated to common shares	$(477,568)	$614	$(993,112)	$21,502
Weighted average common shares outstanding	75,932	75,613	75,900	75,592
Basic and diluted earnings (loss) per common share	$(6.29)	$0.01	$(13.08)	$0.28

Shares excluded due to being anti-dilutive (weighted-average)	431	—	308	—

10. Dividends

During the nine months ended September 30, 2015, we did not declare or pay any dividends. During the nine months ended September 30, 2014, we paid regular cash dividends per common share of $0.10 each quarter. No dividends were paid during the nine months ended September 30, 2015 and dividends have been suspended.

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11. Contingencies

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 relative to such underpayment. We believe the fine is improper and 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 March 2014 notice. We are currently engaged in discovery with the ONRR. We intend to contest the fine to the fullest extent possible. 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, 2015 or December 31, 2014 per authoritative guidance.

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”) related to 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 unspecified actual damages, interest, court costs, and attorneys’ fees. In February 2015, we made a payment to Apache for our net share of the amounts that we believe are reasonable to plug and abandon the three wells, all of which was originally recorded as an asset retirement obligation and was accrued on our Condensed Consolidated Balance Sheet as of December 31, 2014. Our estimate of the potential exposure ranges from zero to $32 million related to this matter, which excludes potential interest, court costs and attorneys’ fees.

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 $42 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 their portion of the settlement (approximately $5 million), in addition to a portion of interest owed. The other underwriters have not paid in accordance with the Fifth Circuit ruling, 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, Starr Marine has paid their portion ($5 million) of the first excess liability policy without interest. The lawsuit includes claims for interest underpaid by Liberty Mutual Insurance Co. and interest not paid by Starr Marine. The revised estimate of potential reimbursement is approximately $30 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 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 Board of Land Appeals (the "BLA") under the Department of the Interior. W&T's brief was filed in November 2014 and we expect the briefing before BLA to be completed in 2015.

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. During the nine months ended September 30, 2015, the Company received four final notices from the Bureau of Safety and Environmental Enforcement (the "BSEE") of civil penalties related to Incidents of Noncompliance ("INCs") at various offshore locations. An aggregate $0.2 million has been paid in respect of three of the four final notices. The Company also received three proposed notices from BSEE related to INCs at various offshore locations. The occurrence dates range from June 2012 to June 2014. For the unpaid proposed penalties, 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 proposed amounts by the BSEE for the unpaid proposed penalties totaled $8.1 million. The Company's position is that the proposed civil penalties are excessive given the specific facts and circumstances related to the INCs.

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

Contingent Liability Recorded. There were no material expenses recognized related to accrued and settled claims, complaints and fines for the three and nine months ended September 30, 2015 and 2014. As of September 30, 2015 and December 31, 2014, we had no material amounts recorded in liabilities for claims, complaints and fines.

12. Subsequent Events

On October 15, 2015, we sold certain oil and natural gas property interests to Ajax Resources, LLC (“Ajax”) for approximately $376.1 million in cash and the assumption of certain ARO, subject to certain customary purchase price adjustments. The effective date of the sale was January 1, 2015. 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 were also assigned a non-expense bearing overriding royalty interest (“ORRI”) in production from the working interests assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the prompt month NYMEX trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel. We used a portion of the proceeds of the sale to repay all outstanding borrowings under the revolving bank credit facility, while the remaining balance of approximately $100.0 million was added to available cash.

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

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 will be recognized from the sale.

On October 30, 2015, the Company entered into the third Amendment to the Credit Agreement, which amended the Credit Agreement as follows:

- Eliminated the maximum Leverage Ratio.
- Eliminated the minimum Interest Coverage Ratio.
- Revised the First Lien Leverage Ratio from 2.50:1.00 to 1.50:1.00 effective for the third quarter of 2015.
- Maintained the minimum Current Ratio requirement of 0.75:1.00 through the fourth quarter of 2015 and maintained increasing the ratio to 1.00:1.00 in the first quarter of 2016.
- Maintained the maximum Secured Debt Leverage Ratio requirement at 3.50:1.00.
- Permitted uncapped bond and term loan repurchases subject to:
  - the revolver loan balance outstanding being $0, after giving effect to such repurchases;
  - having a minimum borrowing base of $200 million;
  - having a maximum outstanding letters of credit balance of $100 million;
  - having no Event of Default having occurred or being continuing; and
  - having no Borrowing Base Deficiency occurred, being continuing or resulting therefrom.

The foregoing description of the amendment to the Credit Agreement does not purport to be complete and is qualified in its entirety by reference to the agreement. Capitalized terms used but not defined above have the meanings given to them in the Credit Agreement.

After the fall of 2015 redetermination, the borrowing base was set at $350.0 million effective on October 30, 2015. As such, a proportional amount of the unamortized debt issuance costs will be expensed in the fourth quarter of 2015.

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13. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes, the 9.00% Term Loan and the Credit Agreement (see Note 5 and 12) 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 of the 8.50% Senior Notes 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, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 7,463	$ —	$ —	$ 7,463
Receivables:				
Oil and natural gas sales	15,798	28,157	—	43,955
Joint interest and other	116,178	—	(73,743)	42,435
Total receivables	131,976	28,157	(73,743)	86,390
Deferred income taxes	6,848	1,864	(4,384)	4,328
Prepaid expenses and other assets	24,693	820	—	25,513
Total current assets	170,980	30,841	(78,127)	123,694
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,071,263	2,185,855	—	8,257,118
Furniture, fixtures and other	21,372	—	—	21,372
Total property and equipment	6,092,635	2,185,855	—	8,278,490
Less accumulated depreciation, depletion and amortization	5,229,074	1,609,001	—	6,838,075
Net property and equipment	863,561	576,854	—	1,440,415
Restricted deposits for asset retirement obligations	15,578	—	—	15,578
Other assets	744,364	292,411	(1,016,491)	20,284
Total assets	$ 1,794,483	$ 900,106	$ (1,094,618)	$ 1,599,971
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 101,848	$ 5,621	$ —	$ 107,469
Undistributed oil and natural gas proceeds	27,816	1,054	—	28,870
Asset retirement obligations	64,085	20,503	—	84,588
Accrued liabilities	44,610	68,304	(73,743)	39,171
Total current liabilities	238,359	95,482	(73,743)	260,098
Long-term debt, less current maturities	1,473,348	—	—	1,473,348
Asset retirement obligations, less current portion	191,066	123,972	—	315,038
Deferred income taxes	341	17,216	(4,384)	13,173
Other liabilities	367,120	—	(353,055)	14,065
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	422,633	704,885	(704,885)	422,633
Retained earnings (deficit)	(874,218)	(41,449)	41,449	(874,218)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(475,751)	663,436	(663,436)	(475,751)

Total liabilities and shareholders' equity	$1,794,483	$900,106	$(1,094,618)	$ 1,599,971

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

Condensed Consolidating Balance Sheet as of December 31, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$23,666	$—	$—	$23,666
Receivables:				
Oil and natural gas sales	41,820	25,422	—	67,242
Joint interest and other	142,885	—	(99,240)	43,645
Total receivables	184,705	25,422	(99,240)	110,887
Deferred income taxes	9,797	1,865	—	11,662
Prepaid expenses and other assets	28,728	7,619	—	36,347
Total current assets	246,896	34,906	(99,240)	182,562
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,038,915	2,006,751	—	8,045,666
Furniture, fixtures and other	23,269	—	—	23,269
Total property and equipment	6,062,184	2,006,751	—	8,068,935
Less accumulated depreciation, depletion and amortization	4,442,899	1,132,179	—	5,575,078
Net property and equipment	1,619,285	874,572	—	2,493,857
Restricted deposits for asset retirement obligations	15,444	—	—	15,444
Other assets	974,049	357,992	(1,314,797)	17,244
Total assets	$2,855,674	$1,267,470	$(1,414,037)	$2,709,107
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$188,654	$5,455	$—	$194,109
Undistributed oil and natural gas proceeds	36,130	879	—	37,009
Asset retirement obligations	30,711	5,292	—	36,003
Accrued liabilities	17,437	99,180	(99,240)	17,377
Total current liabilities	272,932	110,806	(99,240)	284,498
Long-term debt, less current maturities	1,360,057	—	—	1,360,057
Asset retirement obligations, less current portion	235,876	118,689	—	354,565
Deferred income taxes	59,616	127,372	—	186,988
Other liabilities	417,885	—	(404,194)	13,691
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	414,580	703,440	(703,440)	414,580
Retained earnings	118,894	207,163	(207,163)	118,894

Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	509,308	910,603	(910,603)	509,308
Total liabilities and shareholders' equity	$ 2,855,674	$ 1,267,470	$ (1,414,037)	$ 2,709,107

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 (income) 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)

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 (income) 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 Operations for the Three Months Ended September 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$145,950	$ 88,571	$ —	$ 234,521
Operating costs and expenses:				
Lease operating expenses	46,793	24,939	—	71,732
Production taxes	1,794	—	—	1,794
Gathering and transportation	2,872	1,243	—	4,115
Depreciation, depletion, amortization and accretion	70,922	57,749	—	128,671
General and administrative expenses	11,450	9,557	—	21,007
Derivative gain	(13,781)	—	—	(13,781)
Total costs and expenses	120,050	93,488	—	213,538
Operating income (loss)	25,900	(4,917)	—	20,983
Loss of affiliates	(5,729)	—	5,729	—
Interest expense:				
Incurred	20,932	851	—	21,783
Capitalized	(1,340)	(851)	—	(2,191)
Other (income) expense, net	(197)			(197)
Income before income tax expense	776	(4,917)	5,729	1,588
Income tax expense	92	812	—	904
Net income (loss)	$684	$ (5,729)	$ 5,729	$ 684

Condensed Consolidating Statement of Operations for the Nine Months Ended September 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$448,107	$ 303,924	$ —	$ 752,031
Operating costs and expenses:				
Lease operating expenses	126,966	62,150	—	189,116

Production taxes	5,628	—	—	5,628
Gathering and transportation	8,452	4,944	—	13,396
Depreciation, depletion, amortization and accretion	203,040	177,173	—	380,213
General and administrative expenses	33,299	30,978	—	64,277
Derivative loss	6,790	—	—	6,790
Total costs and expenses	384,175	275,245	—	659,420
Operating income	63,932	28,679	—	92,611
Earnings of affiliates	16,211	—	(16,211)	—
Interest expense:				
Incurred	63,078	1,625	—	64,703
Capitalized	(4,797)	(1,625)	—	(6,422)
Other (income) expense, net	(205)			(205)
Income before income tax expense	22,067	28,679	(16,211)	34,535
Income tax expense	357	12,468	—	12,825
Net income	$21,710	$ 16,211	$ (16,211)	$ 21,710

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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 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, net	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 obligation settlements	(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 9.00% 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

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, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$21,710	$ 16,211	$ (16,211)	$ 21,710
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	203,040	177,173	—	380,213
Amortization of debt issuance costs and premium	537	—	—	537
Share-based compensation	11,398	—	—	11,398
Derivative loss	6,790	—	—	6,790
Cash payments on derivative settlements	(18,543)	—	—	(18,543)
Deferred income taxes	17,621	(4,796)	—	12,825
Earnings of affiliates	(16,211)	—	16,211	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	9,041	(9,977)	—	(936)
Joint interest and other receivables	1,890	—	—	1,890
Income taxes	(14,381)	17,265	—	2,884
Prepaid expenses and other assets	55,450	(61,646)	27,424	21,228
Asset retirement obligations	(28,492)	(13,519)	—	(42,011)
Accounts payable, accrued liabilities and other	44,296	4,921	(27,424)	21,793
Net cash provided by operating activities	294,146	125,632	—	419,778
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(18,152)	(53,363)	—	(71,515)
Investment in oil and natural gas properties and equipment	(245,561)	(138,392)	—	(383,953)
Changes in operating assets and liabilities associated with investing activities	(2,258)	7,425	—	5,167
Investment in subsidiary	(58,698)	—	58,698	—
Purchases of furniture, fixtures and other	(2,181)	—	—	(2,181)
Net cash used in investing activities	(326,850)	(184,330)	58,698	(452,482)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	378,000	—	—	378,000
Repayments of long-term debt – revolving bank credit facility	(321,000)	—	—	(321,000)
Dividends to shareholders	(22,695)	—	—	(22,695)
Other	(181)	—	—	(181)

Investment from parent	—	58,698	(58,698)	—
Net cash provided in financing activities	34,124	58,698	(58,698)	34,124
Increase in cash and cash equivalents	1,420	—	—	1,420
Cash and cash equivalents, beginning of period	15,800	—	—	15,800
Cash and cash equivalents, end of period	$17,220	$—	$—	$17,220

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, 2014 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 60 producing offshore fields in federal and state waters (56 producing and four fields capable of producing). We have interests in offshore leases covering approximately 0.9 million gross acres (0.6 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. On a gross acreage basis, the conventional shelf constitutes approximately 59% and deepwater constitutes approximately 41% of our offshore acreage. A substantial amount of our interest in onshore acreage was sold in October 2015, as discussed below, and most of the remaining onshore acreage interest is expected to be terminated, relinquished or sold by year end; therefore, our interest in onshore acreage is expected to be minimal by the end of 2015. A substantial 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-own subsidiary, Energy VI. In managing our business, we are concerned primarily with maximizing return on shareholders' equity. To accomplish this primary goal, we focus on increasing production and reserves at a profit. We strive to grow our reserves and production through acquisitions and our drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to continue to add reserves post-acquisition.

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, 2015 were comprised of 44.7% oil and condensate, 9.6% NGLs and 45.7% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel oil equivalent ("Boe") for oil, NGLs and natural gas has differed significantly from time to time. In the nine months ended September 30, 2015, revenues from the sale of oil and NGLs made up 73.9% of our total revenues compared to

77.2% for the same period of 2014. For the nine months ended September 30, 2015, our combined total production was 0.9% lower than the same period in 2014 due to lower NGLs and natural gas production, partially offset by higher oil production. For the nine months ended September 30, 2015, our total revenues were 46.4% lower than the same period in 2014 due to significantly lower realized prices for oil, NGLs and natural gas. See Results of Operations – Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014 for additional information on our revenues and production.

On October 15, 2015, we sold certain onshore oil and natural gas property interests to Ajax pursuant to a certain purchase and sale agreement for approximately $376.1 million in cash and the assumption of certain ARO, subject to certain customary purchase price adjustments. The effective date of the sale was January 1, 2015. 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 were also assigned a non-expense bearing ORRI in production from the working interest assigned to Ajax, which percentage varies on a sliding scale from one percent for each month that the prompt month NYMEX trading price for light sweet crude 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. The proceeds of the transaction were used to pay down the outstanding balance of the revolving bank credit facility, while the remaining balance of approximately $100.0 million was added to available cash.

In September 2014, we acquired an additional ownership interest in the Fairway Field and associated Yellowhammer gas processing plant, which increased our ownership interest from 64.3% to 100%. The Fairway Field (Mobile Bay blocks 113 and 132) is located in the state waters of Alabama and the Yellowhammer gas processing plant is located in the state of Alabama. Operating results for the increased ownership interest in Fairway are included in our results since the closing date of September 15, 2014. The results for the nine months ended September 30, 2014 contain only one-half month of activity at the higher ownership interest. See Financial Statements - Note 2 - Acquisitions and Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

In May 2014, we acquired certain oil and natural gas property interests in the Gulf of Mexico from Woodside. The Woodside Properties consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in the Neptune tension-leg platform, associated production facilities and various interests in 24 other deepwater blocks. Operating results for the Woodside Properties are included in our results since the closing date of May 20, 2014. See Financial Statements - Note 2 - Acquisitions and Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

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 the nine months ended September 30, 2015, 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. The current market imbalance is predominantly supply driven caused by a number of issues that are described below:

The U.S. Energy Information Administration ("EIA") estimates the worldwide crude oil and petroleum liquids supply will exceed demand in 2015 and 2016, resulting in crude oil and other petroleum liquids inventories increasing by 1.8 million and 0.6 million barrels per day, respectively. This is on top of inventory builds of 0.9 million barrels per day in 2014. EIA estimates that the inventory build was lower in the third quarter of 2015 compared to the second quarter of 2015 and projects the inventory build rate to be lower in the fourth quarter of 2015 compared to the third quarter of 2015. For 2016, EIA projects lower inventory builds compared to projected 2015 amounts, but inventory builds nonetheless. These inventory builds are expected to continue to exert downward pressure on prices. Comparing the nine months ended September 30, 2015 to the same period in 2014, worldwide supply increased 2.8 million barrels per day, or 3.0%, with OPEC and the U.S. having the largest increases in production. Consumption for the nine months ended September 30, 2015 increased by 1.4 million barrels per day, or 1.5%, over the same period in 2014 led by large consumption increases in the U.S. and China. However, concerns have been raised on whether the forecasts for China's crude oil consumption and economic growth are too high and need to be reduced. Saudi Arabia, which has the most flexibility from an economic and production control standpoint, has indicated it will not decrease production in the near future. Many countries, such as Russia, Iraq, Iran and Venezuela, have economies that are highly or solely dependent on oil revenues and do not have significant cash reserves like Saudi Arabia; therefore, production reductions from these countries is not expected. The recent agreement reached between Iran and various other governments, including the United States, requires certifications of Iran's nuclear capabilities before various sanctions are lifted, including the ability to export crude oil legally. The lifting of sanctions on Iran would add more supply to an already oversupplied crude oil market. Iran is expected to increase production and consumption in 2016 assuming the implementation of the Joint Comprehensive Plan of Action between Iran and the five permanent members of the United Nations Security Council plus Germany, which was announced in July 2015.

While many U. S. producers have reduced capital budgets for 2015 compared to 2014 and the number of drilling rigs searching for oil and gas have fallen dramatically (discussed below), EIA projects U.S. petroleum and other liquids production to increase in 2015 over 2014 by 0.9 million barrels per day, which continues to pressure crude oil prices. In addition, the increasing strength in the U.S. dollar relative to other currencies has also had 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, 2015, our average realized oil sales price was $47.81, down from $97.89 per barrel (51.2% lower) for the same period in 2014. The two primary benchmarks reported upon are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $50.94 per barrel for the nine months ended September 30, 2015, down from $99.97 per barrel (49.0% lower) for the same period in 2014. Brent crude average oil prices decreased to $55.31 per barrel for the nine months ended September 30, 2015, down from $106.56 per barrel (48.1% lower) for the same period in 2014. WTI and Brent average crude oil prices in the third quarter of 2015 were lower than the second quarter of 2015 by approximately $10.00 per barrel and our average realized crude oil price in the third quarter of 2015 was lower by $12.78 per barrel, or 22.6%, than the second quarter of 2015. Our average realized oil sales price percentage decrease for the nine months ended September 30, 2015 approximately mirrored the benchmarks and differs due to premiums or discounts (referred to as differentials), volume weighting and other factors. Over 85% of our oil is 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. 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, 2015 were a positive $4.26 and $3.39, and a negative $0.27 per barrel, respectively, compared to positive $4.12 and $4.05, and a negative $1.01 per barrel, respectively, for the same period in 2014. In addition, Permian Basin realized crude oil prices may differ from the WTI benchmark due to infrastructure capacity and transportation costs incurred by the purchaser, with larger discounts applied where the oil is trucked due to lack of pipeline access.

Despite the significant uncertainty and inventory build projections, EIA projects crude oil prices for WTI and Brent to be flat for the fourth quarter of 2015 compared to the third quarter of 2015 and increasing in 2016. EIA estimates 2015 crude oil prices per barrel for WTI and Brent to be $49.53 and $53.57, respectively, and increasing in 2016 to $53.57 and $58.57 per barrel, respectively. Factors identified by EIA that could cause crude oil prices to deviate significantly from their projections is the lifting of oil-related sanctions for Iran, unplanned supply disruptions in certain locations, especially in locations with government instability, and decreases in demand from refinery production from the seasonal summer peaks.

During the nine months ended September 30, 2015, our average realized NGLs sales price decreased 52.8% compared to the same period in 2014. 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, 2015, average prices for domestic ethane decreased 39% and average domestic propane prices decreased 59% from the same period in 2014. Average price decreases for other domestic NGLs were approximately 50%. The price changes were reflective of the price changes for crude oil and natural gas. Production of NGLs have continued to increase in the nine months ended September 30, 2015 causing re-injection of ethane back into the natural gas stream. Propane inventories at the end of September were 45% higher than last year and the highest level since EIA began collecting this data in 1993. New "rich gas" processing capacity added in the fourth quarter of 2014 has increased NGL extraction capability, which has added additional NGLs to an already oversupplied market. From a historical perspective, NGL production from domestic gas plants has increased over three times from 2009 levels (from 1.0 million barrels per day to 3.3 million barrels per day). As long as U.S. crude oil and natural gas production remain high and 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 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. Once propane is extracted from the natural gas stream, it is not re-injected and is sold as a separate component. As propane inventories build with no offsetting increase in demand, propane prices are expected to continue to be weak or weaken further.

During the nine months ended September 30, 2015, our average realized natural gas sales price decreased 37.9% compared to the same period as last year. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 38.7% lower in the nine months ended September 30, 2015 from the same period in 2014. 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. The U.S. natural gas inventories at the end of September 2015 were 15% higher than the same period last year and were 4% above the previous five-year average for this time of the year. EIA projects inventories at the end of October 2015 to be the highest end-of-October level on record. Storage withdrawals in the nine months ended September 30, 2015 were lower than the previous year primarily due to increased production. U.S. consumption increased in the nine months ended September 30, 2015 compared to the previous year, but was significantly less than the production increase. Consumption increases came from higher electric power usage, while residential and commercial usage was lower.

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

EIA projects natural gas prices to increase slightly in the fourth quarter of 2015 compared to the nine months ended September 30, 2015, by $0.08 per Mcf. EIA estimates natural gas prices (Henry Hub spot price) for the full year 2015 and 2016 at $2.89 and $3.14 per Mcf, respectively. As a reference point, the Henry Hub spot price was $4.52 per Mcf for 2014. U.S. production is projected to be higher in 2015 compared to 2014 by 4% and 2016 is projected to be 1% above 2015, which will continue to exert downward pressure on prices. Natural gas usage for power generation is expected to increase to 31%-32% in 2015 and 2016, up from 27% in 2014 due to lower natural gas prices compared to coal and new Federal regulations related to coal usage.

During the nine months ended September 30, 2015, the number of rigs drilling for oil and natural gas in the U.S. has declined significantly from 2014 levels due to lower crude oil and natural gas prices. According to Baker Hughes, the oil rig count at the beginning of 2014 was 1,378 and increased to 1,482 at the end of 2014. As of the end of September 2015, the oil rig count was 614, a decrease of 59% from year end 2014 and a five-year low. The U.S. natural gas rig count was 372 at the beginning of 2014 and decreased to 328 at the end of 2014. As of the end of September 2015, the natural gas rig count was 195, a decrease of 41% from year end 2014 and nearly at the 28-year low. In the Gulf of Mexico, there were 59 rigs (39 oil and 20 natural gas) at the beginning of 2014 and 54 rigs (42 oil and 12 natural gas) at the end of 2014. As of the end of September 2015, there were 29 rigs (22 oil and seven natural gas), the majority of which were “floaters” rather than jack-up rigs, in the Gulf of Mexico, a decrease of 46% from year end 2014.

As required by the full cost accounting rules, we performed our ceiling test calculation as of September 30, 2015 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, 2015 was $55.73 per barrel for WTI crude oil and $3.06 per MMBtu for Henry Hub natural gas before adjustments. For reference, the comparable prices as of October 1, 2015 were $41.25 per barrel for crude oil and $2.48 per MMBtu for natural gas. 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 for the three and nine months ended September 30, 2015 of $441.7 million and $954.9 million, respectively. We are required to perform the ceiling test calculation at the end of each quarter. 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, the cost of future development costs and the future lease operating costs.

At this time, we expect to incur a further ceiling test impairment write-down in the fourth quarter of 2015 assuming commodities prices do not increase dramatically. While it is difficult to project future impairment write-downs in light of numerous variables involved, the following analysis using basic assumptions is provided to illustrate the impact of lower commodities pricing on impairment charges and proved reserves volumes. Applying the actual October 1, 2015 benchmark commodities prices of $41.25 per barrel for WTI crude oil and $2.48 per MMBtu for Henry Hub natural gas (before adjustments) to November 1, 2015 and December 1, 2015, we forecast that the benchmark 12-month average price applicable to year-end 2015 proved reserves under SEC rules would decrease to $46.90 per barrel for WTI crude oil and $2.66 per MMBtu for Henry Hub natural gas before adjustments. If such pricing was used in applying our September 30, 2015 ceiling test for impairment and assuming no other changes, our ceiling test impairment write-down for the quarter ended September 30, 2015 would have increased by $321 million. Applying November 1, 2015 prices and computing a revised estimate would have resulted in a minimal impact on the estimated amount.

Based on internal estimates using the SEC-mandated historical twelve-month unweighted average pricing at such date, our total proved reserves were 79.1 MMBoe at September 30, 2015, excluding approximately 19.1 MMBoe attributable to our Yellow Rose properties which were sold in October 2015. This estimate includes proved developed reserves added since December 31, 2014 but includes no additions of proved undeveloped reserves. If such reserves estimates were made using the further reduced twelve-month average benchmark prices forecast for year-end 2015 proved reserves as described in the foregoing paragraph, our internally estimated proved reserves as of September 30, 2015, excluding recently sold Yellow Rose reserves, would decrease approximately 3.9 MMBoe. This is primarily as a result of the loss of one of our offshore proved undeveloped location which would not be economically producible at such prices, and many fields would experience a shortened time horizon. The foregoing estimate was made without regard to additions or other further revisions to proved reserves estimated at September 30, 2015 other than as a result of such pricing changes.

Our proved reserves estimates as of December 31, 2015 and their estimated discounted value and standardized measure will also be impacted by changes in lease operating costs, future development costs, production, exploration and development activities. All reserve amounts provided in this Form 10-Q are estimates determined by company reservoir engineers and accordingly have not been fully assessed by our independent petroleum consultants as of September 30, 2015.

During the nine months ended September 30, 2015, we entered into two amendments to our Credit Agreement, which (i) reset the borrowing base under our revolving credit facility, (ii) revised the formula for reductions to the borrowing base for additional indebtedness until the borrowing base has been redetermined by the lenders, (iii) amended certain existing covenants and, (iv) provided for an Intercreditor Agreement among lenders under the Credit Agreement and 9.00% Term Loan. Also during the nine months ended September 30, 2015, we entered into the 9.00% Term Loan, with the net proceeds used to pay down a portion of the borrowings outstanding on the revolving bank credit facility. After the issuance of 9.00% Term Loan and the application of the provisions of the Credit Agreement, the borrowing base was $500.0 million as of September 30, 2015. During October 2015, the borrowing base was adjusted for the sale of our interests in the Yellow Rose field and was also redetermined, resulting in a borrowing base of $350.0 million effective October 30, 2015. In addition, a third amendment was entered into which changed or eliminated certain financial covenants. See Financial Statements – Note 5 – Long-Term Debt and Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q for additional information.

The Bureau of Ocean Energy Management (the “BOEM”) has requested additional supplement bonds or surety in order to maintain compliance with BOEM current and contemplated revised regulations related to financial assurance. These additional requirements could increase the costs of our operations and could impact our liquidity if letters of credit are required to obtain such bonds or surety. We are in discussions with the BOEM to provide for an acceptable financial assurance plan. See Part II, Item 1A, Risk Factors, for additional discussion on this matter.

Weak commodity prices in the nine months ended September 30, 2015 have had a significant impact on our business, as discussed in the section titled Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014 under this Item. For a discussion of the potential impact of weak commodity prices in the future, see the section titled Liquidity and Capital Resources under this Item.

On the cost side, we have seen relatively significant reductions in our lease operating expenses as our vendors have reduced their rates for supplies, equipment and contract labor. Combined with reductions in activities, this has resulted in reduced lease operating costs and lower capital expenditures.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. At this time, we are unable to assess the potential impact as clarification is needed for items within the proposals.

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,				Nine Months Ended September 30,			
	2015	2014	Change	%	2015	2014	Change	%
	(In thousands, except percentages and per share data)				(In thousands, except percentages and per share data)			
Financial: (1)								
Revenues:								
Oil	$86,521	$167,194	$(80,673)	(48.3)%	$276,127	$523,323	$(247,196)	(47.2)%
NGLs	6,515	16,950	(10,435)	(61.6)%	21,792	57,538	(35,746)	(62.1)%
Natural gas	31,355	48,359	(17,004)	(35.2)%	100,015	167,801	(67,786)	(40.4)%
Other	1,837	2,018	(181)	(9.0)%	5,267	3,369	1,898	56.3 %
Total revenues	126,228	234,521	(108,293)	(46.2)%	403,201	752,031	(348,830)	(46.4)%
Operating costs and expenses:								
Lease operating expenses	45,039	71,732	(26,693)	(37.2)%	143,500	189,116	(45,616)	(24.1)%
Production taxes	889	1,794	(905)	(50.4)%	2,526	5,628	(3,102)	(55.1)%
Gathering and transportation	3,572	4,115	(543)	(13.2)%	13,189	13,396	(207)	(1.5)%
Depreciation, depletion, amortization and accretion	97,329	128,671	(31,342)	(24.4)%	326,138	380,213	(54,075)	(14.2)%
Ceiling test write-down of oil and natural gas properties	441,688	—	441,688	NM	954,850	—	954,850	NM
General and administrative expenses	16,515	21,007	(4,492)	(21.4)%	57,038	64,277	(7,239)	(11.3)%
Derivative (gain) loss	(10,231)	(13,781)	3,550	NM	(9,153)	6,790	(15,943)	NM
Total costs and expenses	594,801	213,538	381,263	178.5%	1,488,088	659,420	828,668	125.7%
Operating income (loss)	(468,573)	20,983	(489,556)	NM	(1,084,887)	92,611	(1,177,498)	NM
Interest expense, net of amounts capitalized	26,551	19,592	6,959	35.5 %	71,806	58,281	13,525	23.2 %

Other (income) expense, net	964	(197)	1,161	NM	2,647	(205)	2,852	NM
Income (loss) before income tax expense (benefit)	(496,088)	1,588	(497,676)	NM	(1,159,340)	34,535	(1,193,875)	NM
Income tax expense (benefit)	(18,520)	904	(19,424)	NM	(166,228)	12,825	(179,053)	NM
Net income (loss)	$(477,568)	$684	$(478,252)	NM	$(993,112)	$21,710	$(1,014,822)	NM
Basic and diluted earnings (loss) per common share	$(6.29)	$0.01	$(6.30)	NM	$(13.08)	$0.28	$(13.36)	NM

(1) In the second quarter of 2014, we acquired the Woodside Properties and, in the third quarter of 2014, we acquired the remaining working interest in Fairway that we did not already own.

NM – not meaningful

	Three Months Ended September 30, 2015	2014	Change	% (3)	Nine Months Ended September 30, 2015	2014	Change	% (3)
Operating: (1) (2)								
Net sales:								
Oil (MBbls)	1,973	1,758	215	12.2 %	5,776	5,346	430	8.0 %
NGLs (MBbls)	389	506	(117)	(23.1)%	1,241	1,544	(303)	(19.6)%
Natural gas (MMcf)	11,635	12,183	(548)	(4.5)%	35,470	36,951	(1,481)	(4.0)%
Total oil equivalent (MBoe)	4,302	4,295	7	0.2 %	12,928	13,049	(121)	(0.9)%
Total natural gas equivalents (MMcfe)	25,810	25,770	40	0.2 %	77,569	78,291	(722)	(0.9)%
Average daily equivalent sales (Boe/day)	46,757	46,684	73	0.2 %	47,356	47,797	(441)	(0.9)%
Average daily equivalent sales (Mcfe/day)	280,541	280,105	436	0.2 %	284,137	286,781	(2,644)	(0.9)%
Average realized sales prices:								
Oil ($/Bbl)	$43.85	$95.10	$(51.25)	(53.9)%	$47.81	$97.89	$(50.08)	(51.2)%
NGLs ($/Bbl)	16.74	33.47	(16.73)	(50.0)%	17.57	37.26	(19.69)	(52.8)%
Natural gas ($/Mcf)	2.69	3.97	(1.28)	(32.2)%	2.82	4.54	(1.72)	(37.9)%
Oil equivalent ($/Boe)	28.92	54.13	(25.21)	(46.6)%	30.78	57.38	(26.60)	(46.4)%
Natural gas equivalent ($/Mcfe)	4.82	9.02	(4.20)	(46.6)%	5.13	9.56	(4.43)	(46.3)%
Average per Boe ($/Boe):								
Lease operating expenses	$10.47	$16.70	$(6.23)	(37.3)%	$11.10	$14.49	$(3.39)	(23.4)%
Gathering and transportation	0.83	0.96	(0.13)	(13.5)%	1.02	1.03	(0.01)	(1.0)%
Production costs	11.30	17.66	(6.36)	(36.0)%	12.12	15.52	(3.40)	(21.9)%
Production taxes	0.21	0.42	(0.21)	(50.0)%	0.20	0.43	(0.23)	(53.5)%
DD&A	22.62	29.96	(7.34)	(24.5)%	25.23	29.14	(3.91)	(13.4)%
General and administrative expenses	3.84	4.89	(1.05)	(21.5)%	4.41	4.93	(0.52)	(10.5)%
	$37.97	$52.93	$(14.96)	(28.3)%	$41.96	$50.02	$(8.06)	(16.1)%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$1.74	$2.78	$(1.04)	(37.4)%	$1.85	$2.42	$(0.57)	(23.6)%
Gathering and transportation	0.14	0.16	(0.02)	(12.5)%	0.17	0.17	—	0.0 %
Production costs	1.88	2.94	(1.06)	(36.1)%	2.02	2.59	(0.57)	(22.0)%
Production taxes	0.03	0.07	(0.04)	(57.1)%	0.03	0.07	(0.04)	(57.1)%
DD&A	3.77	4.99	(1.22)	(24.4)%	4.20	4.86	(0.66)	(13.6)%
General and administrative expenses	0.64	0.82	(0.18)	(22.0)%	0.74	0.82	(0.08)	(9.8)%
	$6.32	$8.82	$(2.50)	(28.3)%	$6.99	$8.34	$(1.35)	(16.2)%

(1) In the second quarter of 2014, we acquired the Woodside Properties and, in the third quarter of 2014, we acquired the remaining working interest in Fairway that we did not already own.
(2) 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.

(3) Variance percentages are calculated using rounded figures and may result in slightly 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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015	2014	Change	%	2015	2014	Change	%
Wells drilled (gross):								
Offshore	1	—	1	N/A	5	3	2	66.7 %
Onshore	—	6	(6)	(100.0)%	5	28	(23)	(82.1)%
Productive wells drilled (gross)								
Offshore	1	—	1	N/A	5	3	2	66.7 %
Onshore	—	6	(6)	(100.0)%	5	28	(23)	(82.1)%

Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014

Revenues. Total revenues decreased $108.3 million, or 46.2%, to $126.2 million for the third quarter of 2015 as compared to the third quarter of 2014. Oil revenues decreased $80.7 million, or 48.3%, NGLs revenues decreased $10.4 million, or 61.6%, natural gas revenues decreased $17.0 million, or 35.2% and other revenues decreased $0.2 million. The decrease in oil revenues was attributable to a 53.9% decrease in the average realized sales price to $43.85 per barrel for the third quarter of 2015 from $95.10 per barrel for the third quarter of 2014, partially offset by a 12.2% increase in sales volumes. The decrease in NGLs revenues was attributable to a 50.0% decrease in the average realized sales price to $16.74 per barrel for the third quarter of 2015 from $33.47 per barrel for the third quarter of 2014 and a decrease of 23.1% in sales volumes. The decrease in natural gas revenues resulted from a 32.2% decrease in the average realized natural gas sales price to $2.69 per Mcf for the third quarter of 2015 from $3.97 per Mcf for the third quarter of 2014 and from a decrease of 4.5% in sales volumes. We experienced increases in production at the Mississippi Canyon 582 field (Medusa), the Ship Shoal 349 field (Mahogany), the Fairway field, in which we had increased our ownership interest in 2015, and a number of other fields. Production was negatively impacted for all commodities from natural production declines and production deferrals affecting various fields. Production deferrals, which occurred at multiple locations, were attributable to third-party pipeline outages, operational issues, and maintenance. We estimate production deferrals were 0.6 MMBoe during both the third quarter of 2015 and the third quarter of 2014.

Revenues from oil and liquids as a percent of our total revenues were 73.7% for the third quarter of 2015 compared to 78.5% for the third quarter of 2014. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 38.2% for the third quarter of 2015 compared to 35.2% for the third quarter of 2014 because of the precipitous decline in crude oil prices.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, workover and maintenance expenses on our facilities, insurance premiums and insurance reimbursements, decreased $26.7 million to $45.0 million, or 37.2%, in the third quarter of 2015 compared to the third quarter of 2014. On a per Boe basis, lease operating expenses decreased to $10.47 per Boe in the third quarter of 2015 compared to $16.70 per Boe in the third quarter of 2014. On a component basis, base lease operating expenses decreased $10.1 million primarily due to decreased costs from service providers and less downhole onshore well work. Facilities maintenance expenses decreased $7.8 million due to reduced activity at multiple offshore locations. Workover expenses decreased $6.9 million primarily due to offshore activity at High Island 111 performed in the 2014 period. Insurance premiums, net of reimbursements, decreased $1.8 million.

Production taxes. Production taxes decreased $0.9 million to $0.9 million for the third quarter of 2015 compared to the third quarter of 2014. The decrease is primarily due to lower commodity prices for onshore operations. Most of our production is from federal waters where no production taxes are imposed. Our onshore fields and the Fairway field, which is in state waters, are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased $0.5 million to $3.6 million for the third quarter of 2015 compared to the third quarter of 2014.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $22.62 per Boe for the third quarter of 2015 from $29.96 per Boe for the third quarter of 2014. On a nominal basis, DD&A decreased to $97.3 million for the third quarter of 2015 from $128.7 million for the third quarter of 2014 due primarily to a decrease in the DD&A per Boe rate. The DD&A per Boe rate decreased primarily due to the ceiling test write-downs recorded in the first half of 2015 and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. The ceiling test write-down recorded in the third quarter of 2015 will affect the DD&A rate in subsequent quarters. Additional factors affecting the DD&A rate are lower net proved reserves and lower future development costs.

Ceiling test write-down of oil and natural gas properties. For the third quarter of 2015, we recorded a non-cash ceiling test write-down of $441.7 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. No ceiling test write-down was recorded in the third quarter of 2014. See Financial Statements - Note 1 - Basis of Presentation under Part I, Item 1 of this Form 10-Q, which provides a description of the ceiling test limitation determination and above under the section Overview regarding our prospects for a ceiling test write-down in the fourth quarter of 2015, which we believe will be significant.

General and administrative expenses. G&A decreased $4.5 million for the third quarter of 2015 compared to the third quarter of 2014. The decrease is primarily due to lower compensation costs and reduced contractor usage, partially offset by higher medical claims, higher surety bond premium costs and lower billings to joint venture partners. G&A on a per Boe basis was $3.84 per Boe for the third quarter of 2015 compared to $4.89 per Boe for the third quarter of 2014.

Derivative gain. For the third quarter of 2015, there was a $10.2 million derivative gain recorded for derivative contracts for crude oil and natural gas. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015. For the third quarter of 2014, derivative gains were $13.8 million related to derivative contracts for crude oil.

Interest expense. Interest expense incurred for the third quarter of 2015 and 2014 was $28.8 million and $21.8 million, respectively. The increase was primarily attributable to the issuance of the 9.00% Term Loan in May 2015. In addition, the effective interest rate on our revolving bank credit facility was higher in the third quarter of 2015 compared to the third quarter of 2014. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both periods. During the third quarter of 2015 and 2014, $2.2 million of interest was capitalized to unevaluated oil and natural gas properties for each period.

Other (income) expense, net. 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 processes. During the third quarter of 2014, other income, net was $0.2 million.

Income tax expense (benefit). Our income tax benefit for the third quarter of 2015 was $18.5 million compared to income tax expense of $0.9 million for the third quarter of 2014, with the change attributable primarily to a pre-tax loss for the third quarter of 2015 compared to pre-tax income for the third quarter of 2014. Our effective tax rate was 3.7% and differs from the federal statutory rate of 35% primarily due to recording a valuation allowance of $156.2 million 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. Our effective tax rate for the third quarter of 2014 exceeded the statutory rate primarily due to adjustments for a revised estimated effective rate computed on a year-to-date basis. See Financial Statements - Note 8 – Income Taxes under Part I, Item 1 of this Form 10-Q for additional information.

Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014

Revenues. Total revenues decreased $348.8 million, or 46.4%, to $403.2 million for the nine months ended September 30, 2015 as compared to same period in 2014. Oil revenues decreased $247.2 million, or 47.2%, NGLs revenues decreased $35.7 million, or 62.1%, natural gas revenues decreased $67.8 million, or 40.4%, and other revenues increased $1.9 million. The decrease in oil revenues was attributable to a 51.2% decrease in the average realized sales price to $47.81 per barrel for the nine months ended September 30, 2015 from $97.89 per barrel for the same period in 2014, partially offset by an 8.0% increase in sales volumes. The decrease in NGLs revenues was attributable to a 52.8% decrease in the average realized sales price to $17.57 per barrel for the nine months ended September 30, 2015 from $37.26 per barrel for the same period in 2014 and a decrease of 19.6% in sales volumes. The decrease in natural gas revenues resulted from a 37.9% decrease in the average realized natural gas sales price to $2.82 per Mcf for the nine months ended September 30, 2015 from $4.54 per Mcf for the same period in 2014 and from a decrease of 4.0% in sales volumes. We experienced increases in production at a number of fields including the Mississippi Canyon 506 field (Wrigley), which had pipeline outages in 2014, the Fairway field, in which we had increased our ownership interest in 2015, the Ship Shoal 349 field (Mahogany), the Atwater Valley 574 field (Neptune), which was acquired during 2014, and the Mississippi Canyon 582 field (Medusa). Production was negatively impacted for all commodities from natural production declines and production deferrals affecting various fields. Production deferrals were attributable to third-party pipeline outages, operational issues, and maintenance. We estimate production deferrals, which occurred at multiple locations, were 1.8 MMBoe during both the nine months ended September 30, 2015 and 2014 .

Revenues from oil and liquids as a percent of our total revenues were 73.9% for the nine months ended September 30, 2015 compared to 77.2% for the same period in 2014. Our average realized NGLs sales price as a percent of our average realized oil sales price decreased to 36.7% for the nine months ended September 30, 2015 compared to 38.1% for the same period in 2014.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, workover and maintenance expenses on our facilities, insurance premiums and insurance reimbursements, decreased $45.6 million to $143.5 million, or 24.1%, in the nine months ended September 30, 2015 compared to the same period in 2014. On a per Boe basis, lease operating expenses decreased to $11.10 per Boe in the nine months ended September 30, 2015 compared to $14.49 per Boe for the same period in 2014. On a component basis, base lease operating expenses decreased $19.3 million primarily due to decreased costs from service providers and less downhole onshore well work, partially offset by costs related to the acquisition of the Neptune field during the second quarter of 2014. Facilities maintenance expenses decreased $15.6 million due to reduced activity at multiple offshore locations. Workover expenses decreased $8.5 million primarily due to offshore activity at High Island 111 performed in the 2014 period and reductions in onshore activity. Insurance premiums, net of reimbursements, decreased $2.3 million.

Production taxes. Production taxes decreased $3.1 million to $2.5 million for the nine months ended September 30, 2015 compared to the same period in 2014. The decrease is primarily due to lower commodity prices for onshore operations. Most of our production is from federal waters where no production taxes are imposed. Our onshore fields and the Fairway field, which is in state waters, are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased $0.2 million to $13.2 million for the nine months ended September 30, 2015 compared to the same period in 2014.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $25.23 per Boe for the nine months ended September 30, 2015 from $29.14 per Boe for the same period in 2014. On a nominal basis, DD&A decreased to $326.1 million for the nine months ended September 30, 2015 from $380.2 million for the same period in 2014 due to a decrease in the DD&A per Boe rate. The DD&A per Boe rate decreased primarily due to the ceiling test write-downs recorded in the first half of 2015 and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. The ceiling test write-down recorded in the third quarter of 2015 will affect the DD&A rate in subsequent quarters. Additional factors affecting the DD&A rate are lower future development costs and lower proved reserves.

Ceiling test write-down of oil and natural gas properties. For the nine months ended September 30, 2015, we recorded a non-cash ceiling test write-down of $954.9 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. No ceiling test write-down was recorded in the nine months ended September 2014. See Financial Statements - 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 regarding our prospects for a future significant ceiling test write-down.

General and administrative expenses. G&A decreased to $57.0 million for the nine months ended September 30, 2015 from $64.3 million for the same period in 2014 primarily due to lower incentive compensation expenses and lower usage of contractors, partially offset by lower billings to joint venture partners and from recording a contingent assessment provision. G&A on a per Boe basis was $4.41 per Boe for the nine months ended September 30, 2015 compared to $4.93 per Boe for the same period in 2014.

Derivative (gain) loss. For the nine months ended September 30, 2015, there was a $9.2 million derivative gain recorded for derivative contracts for crude oil and natural gas. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015. For the nine months ended September 30, 2014, derivative net losses were $6.8 million related to derivative contracts for crude oil.

Interest expense. Interest expense incurred for the nine months ended September 30, 2015 and 2014 was $77.8 million and $64.7 million, respectively. The increase was primarily attributable to the issuance of the 9.00% Term Loan in May 2015. In addition, the average outstanding balance and the interest rate on the average outstanding balance on our revolving bank credit facility were higher in the nine months ended September 30, 2015 compared to the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both periods. During the nine months ended September 30, 2015 and 2014, $6.0 million and $6.4 million, respectively, of interest were capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying certain unevaluated properties to the full cost pool during the fourth quarter of 2014.

Other (income) expense, net. During the nine months ended September 30, 2015, $2.6 million of net expense was recorded. During the nine months ended September 30, 2015, the borrowing base on the revolving bank credit facility was reduced after the semi-annual redetermination and in conjunction with the issuance of the 9.00% Term Loan pursuant to the terms of the Credit Agreement. The reductions in the borrowing base resulted in proportional reductions in the unamortized debt issuance costs of $2.0 million related to the revolving bank credit facility. In addition, a net loss on sale of assets of $1.0 million was recorded primarily related to the sale of computer equipment used for backup processes, and was partially offset by gains from sales of other assets of $0.3 million. During the nine months ended September 30, 2014, other income, net was $0.2 million.

Income tax expense. Our income tax benefit for the nine months ended September 30, 2015 was $166.2 million compared to income tax expense of $12.8 million for the same period in 2014, with the change attributable primarily to a pre-tax loss for the nine months ended September 30, 2015 compared to pre-tax income for the same period of 2014. Our effective tax rate was 14.3% and differs from the federal statutory rate of 35% primarily due to recording a valuation allowance of $241.6 million 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. Our effective tax rate for the nine months ended September 30, 2014 was 37.1% and differed from the federal statutory rate of 35% primarily as a result of state income taxes and other permanent differences. See Financial Statements - Note 8 – Income Taxes under Part I, Item 1 of this Form 10-Q for additional information.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings, make related interest payments and satisfy our asset retirement obligations. We have funded such activities with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings. These sources of liquidity have historically been sufficient to fund our ongoing cash requirements.

Cash flow and working capital. Net cash provided by operating activities for the nine months ended September 30, 2015 was $134.8 million compared to $419.8 million for the same period in 2014. Cash flows from operating activities, before changes in working capital and ARO settlements, were $125.8 million in the nine months ended September 30, 2015, a decrease of $289.2 million compared to the $414.9 million generated during the same period in 2014. The change in cash flows excluding working capital and ARO settlements was primarily due to lower realized prices for all our commodities - oil, NGLs and natural gas and only partially offset by lower operating expenses. Our combined average realized sales price per Boe decreased 46.4%, which lowered revenues $374.8 million (before considering changes in volumes).

The changes in working capital and ARO settlements increased operating cash flows by $9.0 million in the nine months ended September 30, 2015 and increased operating cash flows by $4.8 million in the same period of 2014, resulting in a difference of $4.2 million.

Net cash used in investing activities during the nine months ended September 30, 2015 and 2014 was $259.5 million and $452.5 million, respectively, which represents our investments in oil and gas properties and equipment. There were no acquisitions of significance during the nine months ended September 30, 2015. Capital expenditures on an accrual basis of $192.8 million for the nine months ended September 30, 2015 represent approximately 97% of our annual budget for 2015 as some 2014 projects had expenditures in 2015. Capital spending year-to-date is in line with our expectations of the timing of our capital expenditures plan, which was front end loaded. During the nine months ended September 30, 2014, expenditures for the acquisitions of the Woodside Properties and increasing our ownership in Fairway were $71.5 million.

Net cash provided by financing activities for the nine months ended September 30, 2015 and 2014 was $108.5 million and $34.1 million, respectively. Net borrowings of long-term debt increased $115.0 million in the nine months ended September 30, 2015. The net cash provided for the nine months ended 2015 was attributable to the issuance of the 9.00% Term Loan, of which the net proceeds were used to pay down a portion of the balance on our revolving bank credit facility. Outstanding balances on our revolving bank credit facility decreased with the proceeds from the issuance of the 9.00% Term Loan, partially offset by additional borrowings. The net cash provided for the nine months ended September 30, 2014 was attributable to net borrowings of $57.0 million on our revolving bank credit facility, partially offset by dividend payments of $22.7 million.

At September 30, 2015, we had a cash balance of $7.5 million and $234.1 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $500.0 million as of September 30, 2015.

Credit Agreement and long-term debt. At September 30, 2015 and December 31, 2014, $265.0 million and $447.0 million, respectively, were outstanding under our revolving bank credit facility. As noted below, the outstanding balance was paid down subsequent to September 30, 2015. During the nine months ended September 30, 2015, the outstanding borrowings on our revolving bank credit facility ranged from $217.0 million to $533.0 million. During the second quarter of 2015, we entered into a $300.0 million 9.00% Term Loan, which was outstanding as of September 30, 2015 and is more fully described in Financial Statements - Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q. At September 30, 2015 and December 31, 2014, $900.0 million in aggregate principal amount of our 8.50% Senior Notes was outstanding.

Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on several financial ratios, as defined in the Credit Agreement. In October 2015, we entered into an amendment of the Credit Agreement, which changed or eliminated certain of these financial covenants. The amendment also allows, under certain conditions, the ability to repurchase our outstanding bonds or term loans and the ability to refinance the bonds or term loan of the same principal amount. See Financial Statements - Note 5 – Long-Term Debt and Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q for a summary of the financial covenants revised in the recent amendment. We were in compliance with all applicable covenants of the Credit Agreement, the 9.00% Term Loan and the 8.50% Senior Notes as of September 30, 2015.

During October 2015, we used a portion of the proceeds of the sale of the Yellow Rose field interest to repay all outstanding borrowings under the revolving bank credit facility, while the remaining balance of approximately $100.0 million was added to available cash. Also during October 2015, the borrowing base was adjusted for the sale of our interests in the Yellow Rose field and also was redetermined. Effective October 30, 2015, the borrowing base was set at $350.0 million. This provides current liquidity of approximately $450.0 million as of the end of October 2015. We believe that cash provided by operations, borrowings available under our revolving bank credit facility, sales of assets and other external sources of liquidity should be sufficient to fund our ongoing cash requirements, but additional financing could be required if we are successful in finding suitable acquisitions and for future development activities.

If commodity prices decline or remain similar to our average prices realized in the nine months ended September 30, 2015 for an extended period of time, our future revenues, earnings and liquidity would be negatively impacted, as would our ability to invest for future reserve growth. Other potential negative impacts of such price weakness include: a) our ability to meet our financial covenants in future periods, b) recognizing additional ceiling test write-downs of the carrying value of our oil and gas properties, c) reductions in our proved reserves and the estimated value thereof, and d) additional supplemental bonding requirements. As a result, these events could force us to seek alternate financing, such as: a) securities offerings, b) joint ventures, and c) sales of properties. These events could also force us to engage the lenders under the Credit Agreement in discussions regarding further amendments. We may have to reduce future cash outlays for capital expenditures and other activities until such time as operating margins improve sufficiently and market conditions recover or stabilize. Realization of any of these events would depend on the longevity and severity of such price weakness. We have assessed our financial condition, our current liquidity arrangement under the Credit Agreement, the current capital and credit markets and options given different scenarios of commodity prices and believe we will have adequate liquidity to fund our operations, which includes ARO, capital expenditures, future development costs, interest payments and other obligations, through September 30, 2016; however, we cannot predict how an extended period of commodity prices at existing levels will affect our operations and liquidity levels.

As a condition to borrowing funds or obtaining letters of credit under our revolving bank credit facility, we must remain in compliance with the financial ratios in our Credit Agreement and we also must certify to our banks lenders that our representations and warranties contained in the Credit Agreement remain true and correct, including representations about our solvency. If we do not comply with our financial ratios or are unable to make the certification, we would be unable to borrow or obtain letters of credit under our revolving bank credit facility, absent a waiver or amendment from our lenders. Generally, the solvency representation requires us to determine at the time we desire to make a future borrowing, or obtain or extend letters of credit, that the fair market value of our assets exceeds the face amount of our liabilities. The current commodity environment creates substantial uncertainty in determining fair market value of oil and gas assets, which accordingly may impact our ability to continue to give the required certification as a condition to future borrowings or issuances or extensions of letters of credit. If we do not meet our financial ratios or are unable to give the required certification, then we would need a waiver or amendment from our bank lenders in order to continue to be able to borrow or obtain letters of credit under our revolving bank credit facility. Although we believe our bank lenders are well secured under the terms of our revolving bank credit facility, there is no assurance that the bank lenders will waive or amend the requirements that are conditions to future lending or issuance of letters of credit.

Derivatives. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of our oil and natural gas. During the second quarter of 2015, we entered into crude oil and natural gas derivative contracts. The volume of open derivative contracts relate to approximately 25% of projected production for the fourth quarter of 2015 and approximately 35% of projected production for 2016. The derivative contracts fulfill requirements stipulated under the Credit Agreement. See Financial Statements - Note 4 - Derivative Financial Instruments and Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q.

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 $161.3 million has been collected through September 30, 2015. In June 2014, the Fifth Circuit reversed a lower court's ruling and compelled our insurance underwriters to reimburse costs incurred by us for removal of wreck related to damages we incurred during Hurricane Ike. Several of the underwriters have not paid 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 $30 million, plus interest, attorney fees and damages, if any. Given the Fifth Circuit's ruling, we expect to be reimbursed and compensated for all these costs, interest, fees and damages. See Financial Statements - Note 11 - Contingencies under Part I, Item 1 of this Form 10-Q.

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 have $75.0 million of named windstorm (hurricane and tropical storm) coverage for certain of our offshore properties and wells and an additional $75.0 million for certain properties and wells at our higher value fields. We have $50.0 million of named windstorm coverage for our lower value offshore properties for the cost of removal in excess of scheduled ARO amounts. The well control, named windstorm and physical damage coverage is effective until June 1, 2016. A per-occurrence retention amount of $30.0 million for named windstorm events must be satisfied by us before our insurers will indemnify us for losses and we co-insure 15% of our named windstorm coverage. The risk exposure varies per property and we have exposure for applicable retentions, co-insurance amounts and coverage limits. We also have other smaller per-occurrence retention amounts for various other events. 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, 2016 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. We have a separate builder's risk and liability policy for certain non-operated properties for platforms and drilling operations under construction, which has coverage net to our interest of $137.0 million and $50.0 million, respectively, with retentions ranging from $0.1 to $0.3 million for different events and is effective until the estimated completion date of December 31, 2015. 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. We qualify to self-insure for $50.0 million of this amount and the remaining $100.0 million is covered by insurance.

The BOEM has requested additional supplement bonds or surety in order to maintain compliance with BOEM current and contemplated revised regulations related to financial assurance. These additional requirements could increase the costs of our operations and could impact our liquidity if letters of credit are required to obtain such bonds or surety. We are in discussions with the BOEM to provide for an acceptable financial assurance plan. See Part II, Item 1A, Risk Factors, for additional discussion on this matter.

Although we were able to renew our general and excess liability policies, and Energy Package in May and June of 2015, respectively, 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,	
	2015	2014
	(In thousands)	
Increased interest in Fairway (1)	$1,285	$18,152
Acquisition of Woodside Properties (1)	180	53,363
Exploration (2)	47,699	143,585
Development (2)	130,444	217,009
Seismic, capitalized interest, and other	13,203	23,359
Acquisitions and investments in oil and gas property/equipment	$192,811	$455,468

(1) The amount reported in 2015 represents the final post-closing purchase price adjustment.
(2) 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,	
	2015	2014
	(In thousands)	
Conventional shelf	$10,542	$104,777
Deepwater	153,052	119,196
Deep shelf	215	23,574
Onshore	14,334	113,047
Exploration and development capital expenditures	$178,143	$360,594

Our capital expenditures for the nine months ended September 30, 2015 and 2014 were financed by cash flow from operating activities, borrowings on our revolving bank credit facility and cash on hand. In addition, the issuance of the 9.00% Term Loan indirectly financed a portion of our capital expenditures for the nine months ended September 30, 2015, as the net proceeds were used to pay down a portion of the borrowings on the revolving bank credit facility.

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

	Nine Months Ended September 30,			
	2015		2014	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	—	—	—	—
Non-productive	—	—	—	—
Onshore wells:				

Productive	3	2.3	17	16.3
Non-productive	—	—	—	—
Total development wells	3	2.3	17	16.3
Exploration wells:				
Offshore wells:				
Productive	5	1.2	3	2.2
Non-productive	—	—	—	—
Onshore wells:				
Productive	2	1.9	11	10.9
Non-productive	—	—	—	—
Total exploration wells	7	3.1	14	13.1
Total wells	10	5.4	31	29.4

Exploration activities. During the nine months ended September 30, 2015, the five offshore exploration wells completed were the SS#6 and SS#7 wells at Mississippi Canyon 538 (Medusa), the ST 320 A-5 ST well at Ewing Bank 910 and the #1 and #2 wells at Mississippi Canyon 782 (Dantzler). Production commenced at the two Medusa wells during the second quarter of 2015 and production commenced at the ST 320 A-5 ST well in the third quarter of 2015. Production is expected at the two Dantzler wells during the fourth quarter of 2015 and production is expected at Mississippi Canyon 698 (Big Bend) during the fourth quarter of 2015 from a well completed in 2014. Subsequent to September 30, 2015, we had one offshore well being drilled and one offshore well where drilling is deferred and the rig is stacked on location.

Acquisitions and funding. We intend to continue to pursue acquisitions and joint venture opportunities in the future should we identify attractive opportunities and obtain suitable financing. For example, during 2014, we completed the acquisition of the Woodside Properties and we completed the acquisition of the remaining interest in the Fairway Properties as described in Financial Statements - Note 2 - Acquisitions and Divestitures under Part I, Item 1 of this Form 10-Q. We are actively evaluating opportunities and seek to complement our drilling and development projects with acquisitions providing acceptable rates of return.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. As described above, we sold our interests in our Yellow Rose field in October 2015, which changed our portfolio to being substantially all offshore properties in the Gulf of Mexico. See Financial Statements - Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q for additional information.

Capital Expenditure Budget for 2015. Our current capital expenditure budget for 2015 is $200 million, not including any potential acquisitions. Our spending for 2015 was front-end loaded and is estimated to be greater than the $200 million by $10-$20 million due to 2014 project work being done during 2015. We have approximately $29 million remaining on our 2015 capital budget to spend in the fourth quarter of 2015. The 2015 budget is allotted as follows: 38% for exploration, 61% for development and less than 1% for other items. Geographically, the budget is split 92% for offshore and 8% for onshore, with a substantial majority of offshore dedicated to the deepwater. Through September 2015, we have not closed any acquisitions of significance, but we continue to evaluate opportunities as they arise. We anticipate funding our 2015 capital budget, any potential acquisitions and other expenditures with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility, issuance of the 9.00% Term Loan and proceeds from divestitures. Our 2015 capital budget is subject to change as conditions warrant. We strive to be as flexible as possible and believe this strategy holds the best promise for value creation, growth and managing the volatility inherent in our business.

Income taxes. During the nine months ended September 30, 2015 and 2014, we did not make any income tax payments nor receive any refunds of significance. For the remainder of 2015, we expect that a substantial portion of our income tax will be deferred and payments, if any, will be primarily related to state taxes. We have $292.1 million of Federal net operating loss carryforwards (tax basis) available to offset future federal taxable income in 2015 and forward. We also have $12.1 million of alternative minimum tax credit carryforwards (tax basis) available to be utilized in 2015 and forward.

Dividends. No dividends were paid during the nine months ended September 30, 2015 and dividends have been suspended.

Capital markets and impact on liquidity. As previously discussed, we entered into a 9.00% Term Loan during the second quarter of 2015 and sold our interests in the Yellow Rose field in October 2015. We have assessed our financial condition, our current liquidity arrangement under the Credit Agreement, the current capital and credit markets and options given different scenarios of commodity prices and believe we will have adequate liquidity to fund our operations, which includes ARO, capital expenditures, future development costs, interest payments and other obligations, through September 30, 2016; however, we cannot predict how an extended period of commodity prices at existing levels will affect our operations and liquidity levels.

Contractual obligations. Updated information on certain contractual obligations is provided in Financial Statements – Note 3 – Asset Retirement Obligations, Note 5 – Long-Term and Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q. As of September 30, 2015, drilling rig commitments were approximately $5.5 million compared to $12.6 million as of December 31, 2014. The current drilling rig commitments expire within one year from September 30, 2015. Except for scheduled utilization, other contractual obligations as of September 30, 2015 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, 2014.

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, 2014. 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, 2015 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, 2014. 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, 2014.

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, 2015, we had open derivative contracts related to a portion of estimated production for the remainder of 2015 and for the full-year 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, 2015, we had $265.0 million outstanding on our revolving bank credit facility. During October 2015, the outstanding balance on our revolving bank credit facility was entirely paid down with the proceeds from the sale of our interest in the Yellow Rose field. 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 2.25% to 3.25% depending on the amount outstanding. As of September 30, 2015, 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.

In connection with the preparation and review of the financial statements included in this Quarterly Report on Form 10-Q, we determined that we incorrectly presented Net cash from operating activities and Net cash used in investing activities on the Condensed Consolidated Statement of Cash Flows by not properly adjusting amounts for non-cash activity related to investing activities. This resulted in Net cash from operating activities being understated and Net cash used in investing activities being understated for the three month period ended March 31, 2015 and the six month period ended June 30, 2015. As a result, we will file Form a 10-Q/A amending our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2015 and June 30, 2015 reflecting the restatements to our Condensed Consolidated Statements of Cash Flows contained in the previously filed Form 10-Qs.

Our management carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of September 30, 2015. We identified a material weakness in our internal control over financial reporting whereby our control for review of our Condensed Consolidated Statements of Cash Flows did not operate effectively and failed to identify a significant change in non-cash balance sheet accruals that required adjustment as a non-cash activity. A material weakness period is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. To address the material weakness, we have revised our quarterly cash flow preparation process to include calculations to correctly adjust for non-cash activity related to investing activity and revised our cash flow review controls to specifically review for this and other non-cash reconciling items necessary to properly present our cash flows.

The evaluation performed by our management, which includes our CEO and CFO, has concluded that our disclosure controls and procedures were not effective at a reasonable level of assurance as of September 30, 2015, due to the material weakness identified related to our Condensed Consolidated Statement of Cash Flows.

Other than the changes related to the Condensed Consolidated Statements of Cash Flows discussed above, during the quarter ended September 30, 2015, there was not any change in our internal control over financial reporting that has 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, 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, 2014, 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 recent decrease 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, 2014 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, 2014, and Part II, Item 1A, Risk Factors in our Quarterly Report on Form 10-Q for the Quarterly period ended June 30, 2015, except as set forth below.

We have been asked by the BOEM to obtain bonds or other surety in order to maintain compliance with BOEM regulations, which could significantly impact the cost of operating our business and could potentially reduce borrowings available under our revolving credit facility.

As discussed in the risk factor in Part I, 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2014, in order to cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees demonstrate financial strength and reliability according to regulations or post bonds or other acceptable assurances that such obligations will be satisfied, unless the BOEM exempts the lessee from such financial assurance requirements. In August 2014, the BOEM issued an Advanced Notice of Proposed Rulemaking ("ANPR") in which the agency indicated that it was considering changing the financial assurance requirements, and it currently plans to publish a Revised Notice to Lessees in late 2015 or early 2016. Part of the ANPR includes the BOEM revising its supplemental bonding procedures by shifting from the current "waiver" model for self-insurance to a credit based model. In October 2015, we received a letter from the BOEM stating that W&T no longer qualifies for waiver of certain supplemental bonding requirements for offshore decommissioning, plugging and abandonment liabilities. The letter notified us that W&T, certain of our subsidiaries and other owners on leases must provide approximately $358 million in supplemental financial assurance and/or bonding for their offshore oil and gas leases, rights-of-way, and rights-of-use and easements. Approximately $56 million of the $358 million requested amount is a result of exempt co-owners losing their exemption. On October 31, 2015, we sent a counter-proposal to the BOEM which reduced the amount of supplemental financial assurance that the BOEM requested. We anticipate the BOEM will respond to our counter-proposal by the end of November 2015.

We currently maintain approximately $6.6 million in lease and/or area bonds issued to the BOEM and approximately $289.3 million in bonds issued to the BOEM or predecessor third party assignors of certain wells and facilities on leases pursuant to a contractual commitment made by us to those third parties at the time of assignment with respect to the eventual decommissioning of those wells and facilities. We also have a State of Alabama bond in the amount of $5.0 million; therefore, our total supplemental bonding is approximately $300.9 million, with an annual premium expense of $ 6.0 million. With respect to our existing bonds, we can provide no assurance that the BOEM will consider them when determining the total value of additional financial assurances and/or bonding we must provide. Furthermore, we anticipate our supplemental bonding requirements to increase as we further develop or acquire additional properties subject to the BOEM's financial assurance requirements.

The BOEM may in the future continue to review our plugging, abandonment, decommissioning and removal obligations; re-evaluate the adequacy of our financial assurances; and require us to provide additional supplemental bonding or other surety for most or all of our properties. The cost of compliance with our existing supplemental bonding requirements or any other changes to the BOEM's current bonding requirements or regulations applicable to us or our properties could be substantial and could materially and adversely affect our financial condition, cash flows, and results of operations. In addition, we may be required to provide letters of credit to support the issuance of these bonds or other surety. Such letters of credit would likely be issued under our credit facility and would reduce the amount of borrowings available under such facility in the amount of any such letter of credits. We can provide no assurance that we can continue to obtain bonds or other surety in all cases, and if we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require any of our operations on federal leases to be suspended or terminated, and such action could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

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 6, 2015.

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
2.1***	Purchase and Sale Agreement, dated August 31, 2015, between W&T Offshore, Inc., as Seller, and Ajax Resources, LLC as Buyer. (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed October 21, 2015 (File No. 001-32414))
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006)
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))
10.5**	Form of Executive Annual Incentive Agreement for Fiscal 2015.
31.1*	Section 302 Certification of Chief Executive Officer.
31.2*	Section 302 Certification of Chief Financial Officer.
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed or Furnished herewith.

** Management Contract or Compensation Plan or
*** Arrangement - filed or furnished herewith.

Pursuant to Item 601(b)(2) of Regulation S-K, the Company agrees to furnish supplementally a copy of any omitted exhibit or schedule to the U.S. Securities and Exchange Commission upon request.

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