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

Form 10-Q

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

For the quarterly period ended June 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 ☑ No ☐

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

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

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

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

As of August 3, 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)

	June 30, 2015	December 31, 2014
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 5,671	$ 23,666
Receivables:		
Oil and natural gas sales	51,957	67,242
Joint interest and other	32,608	43,645
Total receivables	84,565	110,887
Deferred income taxes	6,820	11,662
Prepaid expenses and other assets	27,290	36,347
Total current assets	124,346	182,562
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $110,400 at June 30, 2015 and $109,824 at December 31, 2014 were excluded from amortization)	8,207,165	8,045,666
Furniture, fixtures and other	23,981	23,269
Total property and equipment	8,231,146	8,068,935
Less accumulated depreciation, depletion and amortization	6,306,119	5,575,078
Net property and equipment	1,925,027	2,493,857
Restricted deposits for asset retirement obligations	15,538	15,444
Other assets	20,066	17,244
Total assets	$ 2,084,977	$ 2,709,107
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 135,165	$ 194,109
Undistributed oil and natural gas proceeds	29,693	37,009
Asset retirement obligations	41,494	36,003
Accrued liabilities	13,120	17,377
Total current liabilities	219,472	284,498
Long-term debt, less current maturities	1,468,870	1,360,057
Asset retirement obligations, less current portion	348,573	354,565
Deferred income taxes	34,290	186,988
Other liabilities	14,560	13,691
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at June 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 June 30, 2015; 78,768,588 issued and 75,899,415 outstanding at December 31, 2014	1	1
Additional paid-in capital	420,028	414,580
Retained earnings (deficit)	(396,650)	118,894
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity (deficit)	(788)	509,308
Total liabilities and shareholders' equity	$ 2,084,977	$ 2,709,107

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(In thousands except per share data) (Unaudited)			
Revenues	$ 149,066	$ 262,994	$ 276,973	$ 517,510
Operating costs and expenses:				
Lease operating expenses	45,130	61,765	98,461	117,384
Production taxes	1,000	1,842	1,637	3,834
Gathering and transportation	4,793	3,985	9,617	9,281
Depreciation, depletion, amortization and accretion	103,342	128,236	228,809	251,542
Ceiling test write-down of oil and natural gas properties	252,772	—	513,162	—
General and administrative expenses	19,757	19,682	40,523	43,270
Derivative loss	1,078	13,079	1,078	20,571
Total costs and expenses	427,872	228,589	893,287	445,882
Operating income (loss)	(278,806)	34,405	(616,314)	71,628
Interest expense:				
Incurred	26,116	21,454	49,062	42,912
Capitalized	(2,024)	(2,159)	(3,807)	(4,231)
Debt issuance costs write-off and other, net	1,685	—	1,683	—
Income (loss) before income tax expense (benefit)	(304,583)	15,110	(663,252)	32,947
Income tax expense (benefit)	(44,134)	5,273	(147,708)	11,921
Net income (loss)	$ (260,449)	$ 9,837	$ (515,544)	$ 21,026
Basic and diluted earnings (loss) per common share	$ (3.43)	$ 0.13	$ (6.79)	$ 0.28
Dividends declared per common share	$ —	$ 0.10	$ —	$ 0.20

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	—	—	5,708	—	—	—	5,708
Other	112	—	(260)	—	—	—	(260)
Net loss	—	—	—	(515,544)	—	—	(515,544)
Balances at June 30, 2015	76,011	$ 1	$ 420,028	$ (396,650)	2,869	$ (24,167)	$ (788)

See Notes to Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(In thousands) (Unaudited)	
Operating activities:		
Net income (loss)	$ (515,544)	$ 21,026
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	228,809	251,542
Ceiling test write-down of oil and gas properties	513,162	—
Debt issuance costs write-off/amortization of debt items	2,432	366
Share-based compensation	5,708	7,644
Derivative loss	1,078	20,571
Cash payments on derivative settlements	—	(14,310)
Deferred income taxes	(147,708)	11,921
Changes in operating assets and liabilities:		
Oil and natural gas receivables	15,285	2,335
Joint interest and other receivables	11,036	3,550
Income taxes	(325)	2,918
Prepaid expenses and other assets	8,929	4,439
Asset retirement obligation settlements	(21,939)	(30,338)
Accounts payable, accrued liabilities and other	(70,862)	(10,614)
Net cash provided by operating activities	30,061	271,050
Investing activities:		
Acquisition of property interest in oil and natural gas properties	—	(53,363)
Investment in oil and natural gas properties and equipment	(150,994)	(212,680)
Purchases of furniture, fixtures and other	(709)	(1,715)
Net cash used in investing activities	(151,703)	(267,758)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	194,000	220,000
Repayments of long-term debt - revolving bank credit facility	(381,000)	(200,000)
Issuance of 9.00% Term Loan	297,000	—
Debt issuance costs	(6,407)	—
Dividends to shareholders	—	(15,129)
Other	54	(116)
Net cash provided by financing activities	103,647	4,755
Increase (decrease) in cash and cash equivalents	(17,995)	8,047
Cash and cash equivalents, beginning of period	23,666	15,800
Cash and cash equivalents, end of period	$ 5,671	$ 23,847

See Notes to Condensed Consolidated Financial Statements.

1. Basis of Presentation

Operations. W&T Offshore, Inc. (with subsidiaries referred to herein as "W&T," "we," "us," "our," or the "Company") is an independent oil and natural gas producer focused primarily in the Gulf of Mexico and onshore Texas. 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 six months ended June 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.

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, 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 for the first and second quarters of 2015, we recorded ceiling test write-downs which are reported as a separate line in the *Statements of Operations*. We did not have a ceiling test write-down during 2014. In light of the significantly lower oil and natural gas prices experienced in late 2014 and in the current year, we expect to have an additional significant ceiling test write-down during the third quarter of 2015 and, assuming such prices do not increase dramatically in the last three months of this year, it is possible we could incur a further write-down in the fourth quarter of 2015 as well.

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 first half of 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 and (iv) implementing numerous cost reduction projects to reduce our operating costs.

During the second quarter of 2015, we entered into two Amendments to our Fifth Amended and Restated Credit Agreement (as amended, the "Credit Agreement"), which, among other things, revised certain financial covenants to be less restrictive, modified the borrowing base adjustment for additional debt and authorized the administrative agent under the Credit Agreement to enter into an Intercreditor Agreement among the Company, the lenders under the Credit Agreement and the lenders under the second lien term loan (the "9.00% Term Loan"). The borrowing base of the revolving bank credit facility under the Credit Agreement is currently set at $500.0 million. The 9.00% Term Loan was entered into in the second quarter of 2015, with a principal amount of $300.0 million and matures on May 15, 2020. See Note 5 for additional information on our debt.

We have assessed our financial condition, the current capital markets and options given different scenarios of commodity prices and believe we will have adequate liquidity to fund our operations through June 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 should 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

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.

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	$	52,329
Unevaluated properties		2,660
Sub-total cash consideration		54,989
Non-cash consideration:		
Asset retirement obligations - current		782
Asset retirement obligations - non-current		10,543
Sub-total non-cash consideration		11,325
Total consideration	$	66,314

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 six month periods ended June 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 six month periods ended June 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 June 30, 2015, the Woodside Properties accounted for $7.9 million of revenues, $1.8 million of direct operating expenses, $3.9 million of depreciation, depletion, amortization and accretion (“DD&A”) and $0.8 million of income tax expense, resulting in $1.4 million of net income. For the six months ended June 30, 2015, the Woodside Properties accounted for $13.4 million of revenues, $5.1 million of direct operating expenses, $8.0 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.

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)	
	Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
Revenue	$ 272,022	$ 540,397
Net income	12,150	27,120
Basic and diluted earnings per common share	0.16	0.35

For the pro forma financial information, certain information was derived from our financial records, Woodside’s financial records and certain information was estimated.

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

	(unaudited)	
	Three Months Ended June 30, 2014 (a)	Six Months Ended June 30, 2014 (a)
Revenues (b)	$ 9,028	$ 22,887
Direct operating expenses (b)	1,805	4,417
DD&A (c)	3,387	8,384
G&A (d)	200	400
Interest expense (e)	82	330
Capitalized interest (f)	(5)	(19)
Income tax expense (g)	1,246	3,281

The sources of information and significant assumptions are described below:

(a) The adjustments for the periods 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.

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	(21,939)
Accretion of discount	10,930
Disposition of properties	(965)
Liabilities assumed through acquisition	2,944
Liabilities incurred	4,671
Revisions of estimated liabilities (1)	3,858
Balance, June 30, 2015	390,067
Less current portion	41,494
Long-term	$ 348,573

(1) Revisions were primarily attributable to increases 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 the second quarter of 2015, we entered into crude oil derivative contracts 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 West Texas Intermediate ("WTI") crude oil prices as quoted off the New York Mercantile Exchange, known as NYMEX. The natural gas contracts are based on Henry Hub natural gas prices as quoted off the NYMEX.

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 June 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)	Notional Quantity (Bbls)	Weighted Average Contract Price Put Option (Bought)	Call Option (Sold)	Call Option (Bought)
2015:	3rd Quarter	6,000	552,000	$ 50.00	$ 60.00	$ 62.30
	4th Quarter	6,000	552,000	50.00	60.00	62.30
			1,104,000	50.00	60.00	62.30

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

Termination Period		Notional Quantity (Bbls/day)	Notional Quantity (Bbls)	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)	Notional Quantity (MMBTUs)	Weighted Average Contract Price Put Option (Bought)	Call Option (Sold)	Call Option (Bought)
2015:	3rd Quarter	30,000	1,830,000	$ 2.25	$ 3.25	$ 3.51
	4th Quarter	30,000	2,760,000	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
			19,230,000	2.25	3.44	3.70

(1) 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 July 2015 production were priced and closed in June 2015 and are not included in the above table as these were not open derivative contracts as of June 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):

	June 30, 2015	December 31, 2014
Accrued liabilities	$ 535	$ —
Other liabilities (noncurrent)	544	—

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Derivative loss	$ 1,078	$ 13,079	$ 1,078	$ 20,571

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

	Six Months Ended June 30,	
	2015	2014
Cash payments on derivative settlements, net	$ —	$ 14,310

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 June 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):

	June 30, 2015	December 31, 2014
8.50% Senior Notes due 2019	$ 900,000	$ 900,000
Debt premiums, net of amortization	11,805	13,057
9.00% Term Loan due 2020	300,000	—
Debt discounts, net of amortization	(2,935)	—
Revolving bank credit facility	260,000	447,000
Total long-term debt	1,468,870	1,360,057
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$ 1,468,870	$ 1,360,057

At June 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 June 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. A related party, which was 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 June 30, 2015.

As of June 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 June 30, 2015 and December 31, 2014, we had $0.6 million of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 3.2% for the six months ended June 30, 2015 for 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 June 30, 2015, our borrowing base was $500.0 million and our borrowing availability was $239.4 million.

During the second quarter of 2015, we 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 proved 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 *Debt issuance costs write-off and other, net* on the Statements of Operations.

Under the Credit Agreement, we are subject to various financial covenants, as listed above, which arecalculated as of the last day of each fiscal quarter. We were in compliance with all applicable covenants of the Credit Agreement as of June 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 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, all of which are reported as liabilities on the Condensed Consolidated Balance Sheets (in thousands):

	Hierarchy	June 30, 2015	December 31, 2014
Derivatives	Level 2	$ 1,079	$ —
8.50% Senior Notes due 2019 (1)	Level 2	633,060	594,000
9.00% Term Loan due 2020 (1)	Level 2	296,250	—
Revolving bank credit facility (1)	Level 2	260,000	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 six months ended June 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.

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 apre-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 June 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 June 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	
	Shares	Weighted Average 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, June 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 June 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 first half of 2015 and the first half of 2014 was $0.3 million for both periods. The fair values of Restricted Shares that vested during the first half of 2015 and the first half of 2014 were $0.1 million and $0.3 million, respectively.

Awards Based on Restricted Stock Units. As of June 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 remains 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	(71,890)	15.15
Nonvested, June 30, 2015	1,881,945	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 June 30, 2015 potentially eligible to vest are listed in the table below:

	Restricted Stock Units
2015 - subject to service requirements	706,370
2015 - subject to service and other requirements (1)	86,507
2016 - subject to service requirements	1,089,068
Total	1,881,945

(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 first half of 2014 was $19.9 million. The fair value of RSUs that vested during the first half of 2015 and the first half of 2014 was $0.1 million for both periods.

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Share-based compensation expense from:				
Restricted stock	$ 90	$ 84	$ 183	$ 183
Restricted stock units	2,802	3,625	5,619	6,161
Common shares	—	178	(94)	1,300
Total	$ 2,892	$ 3,887	$ 5,708	$ 7,644
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$ 1,012	$ 1,360	$ 1,998	$ 2,675

Unrecognized Share-Based Compensation. As of June 30, 2015, unrecognized share-based compensation expense related to our awards of Restricted Shares and RSUs was $0.6 million and $10.9 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 first half of 2015, the Company did not issue any cash-based incentive awards for 2015. Amounts recorded during the first half of 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Share-based compensation included in:				
General and administrative expenses	$ 2,892	$ 3,887	$ 5,708	$ 7,644
Cash-based incentive compensation included in:				
Lease operating expense	—	475	364	1,777
General and administrative expenses (1)	—	1,532	(233)	3,313
Total charged to operating income	$ 2,892	$ 5,894	$ 5,839	$ 12,734

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

8. Income Taxes

Our income tax benefit for the three and six months ended June 30, 2015 was $44.1 million and $147.7 million, respectively. The income tax benefit is partially attributable to recording a ceiling test write-down in the three and six months ended June 30, 2015 of $252.8 million and $513.2 million, respectively. Our effective tax rate for the three and six months ended June 30, 2015 was 14.5% and 22.3%, 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 six months ended June 30, 2014 was $5.3 million and $11.9 million, respectively. Our effective tax rate for the three and six months ended June 30, 2014 was 34.9% and 36.2%, respectively, and differed from the federal statutory rate primarily as a result of state income taxes and other permanent items.

During the three and six months ended June 30, 2015, we recorded a valuation allowance of $62.9 million and $85.4 million, respectively, related to federal deferred tax assets and net operating losses. 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 June 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 from 2010 through 2014 remain open to examination by the tax jurisdictions to which we are subject.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the six months ended June 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss)	$ (260,449)	$ 9,837	$ (515,544)	$ 21,026
Less portion allocated to nonvested shares	—	100	—	219
Net income (loss) allocated to common shares	$ (260,449)	$ 9,737	$ (515,544)	$ 20,807
Weighted average common shares outstanding	75,910	75,605	75,884	75,581
Basic and diluted earnings (loss) per common share	$ (3.43)	$ 0.13	$ (6.79)	$ 0.28
Shares excluded due to being anti-dilutive (weighted-average)	355	—	277	—

10. Dividends

During the six months ended June 30, 2015, we did not declare or pay any dividends. During the six months ended June 30, 2014, we paid regular cash dividends per common share of $0.10 each quarter. Pursuant to the financial covenants in the Credit Agreement, the regular quarterly dividend is effectively suspended until June 2016. The suspension imposed by the Credit Agreement will be lifted when the maximum Leverage Ratio, as defined in the Credit Agreement, is reinstated and the Company is able to comply with the covenant. In addition, the dividend may be suspended due to the lack of statutory surplus under state law. See Note 5 for additional information.

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 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 notice. 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 June 30, 2015 or December 31, 2014 per authoritative guidance. However, we cannot state with certainty that our estimate of the exposure is accurate concerning this matter.

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 first half of 2015, the Company received two notices from the Bureau of Safety and Environmental Enforcement (the "BSEE") proposing civil penalties totaling $3.6 million related to Incidents of Noncompliance ("INCs") at two offshore locations, one of which occurred in 2012 and one occurred in 2014. The Company's position is the civil penalties are excessive given the specific facts and circumstances related to the INCs and we have accrued an amount less than the proposed assessment.

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 six months ended June 30, 2015 and 2014. As of June 30, 2015 and December 31, 2014, we had no material amounts recorded in liabilities for claims, complaints and fines.

12. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes, the 9.00% Term Loan and the Credit Agreement (see Note 5) are fully and unconditionally guaranteed by certain of our 100%-owned subsidiaries, including Energy VI and W & T Energy VII, LLC (together, the "Guarantor Subsidiaries"). W & T Energy VII, LLC does not currently have any active operations or contain any assets. Guarantees 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.

Condensed Consolidating Balance Sheet as of June 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 5,671	$ —	$ —	$ 5,671
Receivables:				
Oil and natural gas sales	23,109	28,848	—	51,957
Joint interest and other	114,021	—	(81,413)	32,608
Total receivables	137,130	28,848	(81,413)	84,565
Deferred income taxes	56,955	1,865	(52,000)	6,820
Prepaid expenses and other assets	22,821	4,469	—	27,290
Total current assets	222,577	35,182	(133,413)	124,346
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,064,146	2,143,019	—	8,207,165
Furniture, fixtures and other	23,981	—	—	23,981
Total property and equipment	6,088,127	2,143,019	—	8,231,146
Less accumulated depreciation, depletion and amortization	4,937,933	1,368,186	—	6,306,119
Net property and equipment	1,150,194	774,833	—	1,925,027
Restricted deposits for asset retirement obligations	15,538	—	—	15,538
Other assets	868,316	293,570	(1,141,820)	20,066
Total assets	$ 2,256,625	$ 1,103,585	$ (1,275,233)	$ 2,084,977
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 130,386	$ 4,779	$ —	$ 135,165
Undistributed oil and natural gas proceeds	28,650	1,043	—	29,693
Asset retirement obligations	34,992	6,502	—	41,494
Accrued liabilities	13,543	80,990	(81,413)	13,120
Total current liabilities	207,571	93,314	(81,413)	219,472
Long-term debt, less current maturities	1,468,870	—	—	1,468,870
Asset retirement obligations, less current portion	216,706	131,867	—	348,573
Deferred income taxes	382	85,908	(52,000)	34,290
Other liabilities	363,884	—	(349,324)	14,560
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	420,028	704,885	(704,885)	420,028
Retained earnings (deficit)	(396,650)	87,611	(87,611)	(396,650)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(788)	792,496	(792,496)	(788)
Total liabilities and shareholders' equity	$ 2,256,625	$ 1,103,585	$ (1,275,233)	$ 2,084,977

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

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consol W& Offshor
		(In thousands)		
Revenues	$ 90,465	$ 58,601	$ —	$
Operating costs and expenses:				
Lease operating expenses	30,104	15,026	—	
Production taxes	1,000	—	—	
Gathering and transportation	2,769	2,024	—	
Depreciation, depletion, amortization and accretion	58,023	45,319	—	
Ceiling test write-down of oil and natural gas properties	181,300	71,472	—	
General and administrative expenses	10,856	8,901	—	
Derivative loss	1,078	—	—	
Total costs and expenses	285,130	142,742	—	
Operating loss	(194,665)	(84,141)	—	
Loss of affiliates	(54,548)	—	54,548	
Interest expense:				
Incurred	25,322	794	—	
Capitalized	(1,230)	(794)	—	
Debt issuance costs write-off and other, net	1,685	—	—	
Loss before income tax benefit	(274,990)	(84,141)	54,548	
Income tax benefit	(14,541)	(29,593)	—	
Net loss	$ (260,449)	$ (54,548)	$ 54,548	$

Condensed Consolidating Statement of Operations for the Six Months Ended June 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consol W& Offshor
		(In thousands)		
Revenues	$ 167,808	$ 109,165	$ —	$
Operating costs and expenses:				
Lease operating expenses	67,742	30,719	—	
Production taxes	1,637	—	—	
Gathering and transportation	5,334	4,283	—	
Depreciation, depletion, amortization and accretion	129,374	99,435	—	
Ceiling test write-down of oil and natural gas properties	371,995	141,167	—	
General and administrative expenses	22,615	17,908	—	
Derivative loss	1,078	—	—	
Total costs and expenses	599,775	293,512	—	
Operating loss	(431,967)	(184,347)	—	
Loss of affiliates	(119,552)	—	119,552	
Interest expense:				
Incurred	47,554	1,508	—	
Capitalized	(2,299)	(1,508)	—	
Debt issuance costs write-off and other, net	1,683	—	—	
Loss before income tax benefit	(598,457)	(184,347)	119,552	
Income tax benefit	(82,913)	(64,795)	—	
Net loss	$ (515,544)	$ (119,552)	$ 119,552	$

Condensed Consolidating Statement of Operations for the Three Months Ended June 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 156,033	$ 106,961	$ —	$ 262,994
Operating costs and expenses:				
Lease operating expenses	40,846	20,919	—	61,765
Production taxes	1,842	—	—	1,842
Gathering and transportation	2,232	1,753	—	3,985
Depreciation, depletion, amortization and accretion	68,921	59,315	—	128,236
General and administrative expenses	10,269	9,413	—	19,682
Derivative loss	13,079	—	—	13,079
Total costs and expenses	137,189	91,400	—	228,589
Operating income	18,844	15,561	—	34,405
Earnings of affiliates	10,252	—	(10,252)	—
Interest expense:				
Incurred	20,617	837	—	21,454
Capitalized	(1,322)	(837)	—	(2,159)
Income before income tax expense	9,801	15,561	(10,252)	15,110
Income tax expense (benefit)	(36)	5,309	—	5,273
Net income	$ 9,837	$ 10,252	$ (10,252)	$ 9,837

Condensed Consolidating Statement of Operations for the Six Months Ended June 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 302,156	$ 215,354	$ —	$ 517,510
Operating costs and expenses:				
Lease operating expenses	80,172	37,212	—	117,384
Production taxes	3,834	—	—	3,834
Gathering and transportation	5,580	3,701	—	9,281
Depreciation, depletion, amortization and accretion	132,117	119,425	—	251,542
General and administrative expenses	21,850	21,420	—	43,270
Derivative loss	20,571	—	—	20,571
Total costs and expenses	264,124	181,758	—	445,882
Operating income	38,032	33,596	—	71,628
Earnings of affiliates	21,940	—	(21,940)	—
Interest expense:				
Incurred	41,294	1,618	—	42,912
Capitalized	(2,613)	(1,618)	—	(4,231)
Income before income tax expense	21,291	33,596	(21,940)	32,947
Income tax expense (benefit)	265	11,656	—	11,921
Net income	$ 21,026	$ 21,940	$ (21,940)	$ 21,026

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$ (515,544)	$ (119,552)	$ 119,552	$ (515,544)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	129,374	99,435	—	228,809
Ceiling test write-down of oil and gas properties	371,995	141,167	—	513,162
Debt issuance costs write-off/amortization of debt items	2,432	—	—	2,432
Share-based compensation	5,708	—	—	5,708
Derivative loss	1,078	—	—	1,078
Deferred income taxes	(105,818)	(41,890)	—	(147,708)
Loss of affiliates	119,552	—	(119,552)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	18,710	(3,425)	—	15,285
Joint interest and other receivables	11,036	—	—	11,036
Income taxes	22,580	(22,905)	—	(325)
Prepaid expenses and other assets	(8,913)	72,712	(54,870)	8,929
Asset retirement obligation settlements	(21,146)	(793)	—	(21,939)
Accounts payable, accrued liabilities and other	(125,219)	(513)	54,870	(70,862)
Net cash provided by (used in) operating activities	(94,175)	124,236	—	30,061
Investing activities:				
Investment in oil and natural gas properties and equipment	(25,313)	(125,681)	—	(150,994)
Investment in subsidiary	(1,445)	—	1,445	—
Purchases of furniture, fixtures and other	(709)	—	—	(709)
Net cash used in investing activities	(27,467)	(125,681)	1,445	(151,703)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	194,000	—	—	194,000
Repayments of long-term debt – revolving bank credit facility	(381,000)	—	—	(381,000)
Issuance of 9.00% Term Loan	297,000	—	—	297,000
Debt issuance costs	(6,407)	—	—	(6,407)
Other	54	—	—	54
Investment from parent	—	1,445	(1,445)	—
Net cash provided by financing activities	103,647	1,445	(1,445)	103,647
Decrease in cash and cash equivalents	(17,995)	—	—	(17,995)
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	$ 5,671	$ —	$ —	$ 5,671

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 21,026	$ 21,940	$ (21,940)	$ 21,026
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	132,117	119,425	—	251,542
Amortization of debt issuance costs and premium	366	—	—	366
Share-based compensation	7,644	—	—	7,644
Derivative loss	20,571	—	—	20,571
Cash payments on derivative settlements	(14,310)	—	—	(14,310)
Deferred income taxes	25,078	(13,157)	—	11,921
Earnings of affiliates	(21,940)	—	21,940	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	7,636	(5,301)	—	2,335
Joint interest and other receivables	3,550	—	—	3,550
Income taxes	(21,896)	24,814	—	2,918
Prepaid expenses and other assets	(123,770)	(91,015)	219,224	4,439
Asset retirement obligations	(18,583)	(11,755)	—	(30,338)
Accounts payable, accrued liabilities and other	203,344	5,266	(219,224)	(10,614)
Net cash provided by operating activities	220,833	50,217	—	271,050
Investing activities:				
Acquisition of property interest in oil and natural gas properties	—	(53,363)	—	(53,363)
Investment in oil and natural gas properties and equipment	(157,128)	(55,552)	—	(212,680)
Investment in subsidiary	(58,698)	—	58,698	—
Purchases of furniture, fixtures and other	(1,715)	—	—	(1,715)
Net cash used in investing activities	(217,541)	(108,915)	58,698	(267,758)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	220,000	—	—	220,000
Repayments of long-term debt – revolving bank credit facility	(200,000)	—	—	(200,000)
Dividends to shareholders	(15,129)	—	—	(15,129)
Other	(116)	—	—	(116)
Investment from parent	—	58,698	(58,698)	—
Net cash used in financing activities	4,755	58,698	(58,698)	4,755
Increase in cash and cash equivalents	8,047	—	—	8,047
Cash and cash equivalents, beginning of period	15,800	—	—	15,800
Cash and cash equivalents, end of period	$ 23,847	$ —	$ —	$ 23,847

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 and onshore in the Permian Basin of West Texas. 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 1.0 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. Onshore, we have leasehold interests in approximately 50,000 gross acres (40,000 net acres), substantially all of which are in Texas. A substantial majority of our daily production is derived from wells we operate offshore. 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 first half of 2015 were comprised of 44.1% oil and condensate, 9.9% NGLs and 46.0% 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 first half of 2015, revenues from the sale of oil and NGLs made up 74.0% of our total revenues compared to 76.7% for the same period of 2014. For the first half of 2015, our combined total production was 1.5% lower than the first half of 2014 due to lower NGLs and natural gas production, partially offset by higher production for oil. For the first half of 2015, our total revenues were 46.5% lower than the first half of 2014 due to significantly lower realized prices for oil, NGLs and natural gas. See *Results of Operations – Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014*for additional information on our revenues and production.

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 first half of 2014 do not include the increased ownership interest in Fairway as this period precedes the acquisition date. 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 first half of 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 barrels per day 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 projects the inventory build rate to be lower in the second half of 2015 compared to the first half of 2015, and lower in 2016. These inventory builds are expected to keep downward pressure on prices. Comparing the first half of 2015 to the first half of 2014, worldwide supply increased 2.9 million barrels per day, with the U.S. and OPEC having the largest increases in production. Consumption for the first half of 2015 increased by 1.4 million barrels per day over the first half of 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, 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 proposed agreement reached with Iran by various governments' diplomats still requires the respective governments' formal approval. As currently drafted and if approved, the lifting of sanctions on Iran would add more supply to an already oversupplied crude oil market. The possible increase in production from Iran has not been factored into EIA's projections at this time.

While many U. S. producers have reduced capital budgets for 2015 compared to 2014 and operating drilling rigs have fallen dramatically (discussed below), EIA projects U.S. petroleum and other liquids production to increase in 2015 over 2014 by 1.0 million barrels per day. 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 first half of 2015, our average realized oil sales price was $49.86, down from $99.26 per barrel (49.8% lower) for the first half of 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 $53.25 per barrel for the first half of 2015, down from $101.05 per barrel (47.3% lower) for the first half of 2014. Brent crude oil prices decreased to $57.84 per barrel for the first half of 2015, down from $108.93 per barrel (46.9% lower) for the first half of 2014. Average crude oil prices in the second quarter of 2015 were higher than the first quarter of 2015 by approximately $8.00 - $10.00 per barrel, but as of July 2015, crude oil prices have fallen and are between first quarter and second quarter 2015 levels. Our average realized oil sales price percentage decrease for the first half of 2015 differs from the benchmarks primarily due to the realized prices received for our offshore crude oil production. 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 premiums for our offshore crude oil have declined and sometimes are priced at a discount to WTI. For example, the monthly average premiums to WTI for LLS, HLS and Poseidon for the first half of 2015 were $4.45, $3.72 and $0.15 per barrel, respectively, compared to $4.48, $4.59 and a negative $0.54 per barrel, respectively, for the first half of 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 relatively flat for the second half of 2015 compared to the second quarter of 2015 and increasing in 2016. EIA estimates 2015 crude oil prices per barrel for WTI and Brent to be $55.51 and $60.22, respectively, and increasing in 2016 to $62.04 and $67.04 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 and decreases in demand from refinery production after the seasonal peaks from the summer driving season.

During the first half of 2015, our average realized NGLs sales price decreased 54.1% compared to the first half of 2014. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the first half of 2015, average prices for domestic ethane decreased 45% and average domestic propane prices decreased 58% from the first half of 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 first half of 2015 causing re-injection of ethane back into the natural gas stream and causing propane inventories to exceed the five year average by greater than 60% this time of the year. 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 must be 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 first half of 2015, our average realized natural gas sales price decreased 40.2% compared to the first half of 2014. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 43.8% lower in the first half of 2015 from the first half of 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 June 2015 were 32% higher than last year and were approximately at the previous five-year average for this time of the year. Storage withdrawals in the first half of 2015 were lower than the previous year primarily due to increased production. U.S. consumption increased in the first half of 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 in the second half of 2015 compared to the first half of 2015, with estimated increases ranging from $0.24 to $0.36 per Mcfe. EIA estimates natural gas prices (Henry Hub spot price) for the full year 2015 and 2016 at $3.06 and $3.41 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 and 2016 compared to 2014 by 4%, putting downward pressure on prices. Natural gas usage for power generation is expected to increase to 30% in 2015 and 2016 from 27% in 2014 due to lower natural gas prices compared to coal and new Federal regulations related to coal usage.

During the first half of 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 June 2015, the oil rig count was 640, a decrease of 57% from year end 2014. 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 June 2015, the natural gas rig count was 219, a decrease of 33% from year end 2014. During 2015, the total rig count has fallen each week except for the last two weeks in June 2015, which had a slight increase from the previous week. 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 June 2015, there were 29 rigs (21 oil and eight natural gas) in the Gulf of Mexico, a decrease of 46% from year end 2014.

As required by the full cost accounting rules, we performed our ceilingtest calculation as of June 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 June 30, 2015 was $68.17 per barrel for crude oil and $3.39 per Mcf for natural gas. (For reference, the average prices for the first half of 2015were $53.25 per barrel for WTI crude oil and $2.83 per Mcf for natural gas using Henry Hub spot prices.) Due to the decrease in the 12-month average price for both crude oil and natural gas, we recorded a ceiling test write-down of the carrying value of our oil and natural gas propertiesfor the first half of 2015 of $513.2 million. We are required to perform the ceiling test calculation at the end of each quarter. In light of the significantly lower oil and natural gas prices experienced in late 2014 and in the current year, we expect to have an additional significant ceiling test write-down during the third quarter of 2015 and, assuming such prices do not increase dramatically in the last three months of this year, it is possible we could incur a further write-down in the fourth quarter of 2015 as well.

During the second quarter of 2015, we entered into 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 second quarter of 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 June 30, 2015. The borrowing base will be redetermined in the fall of 2015. See *Financial Statements – Note 5 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information

As discussed in Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2014, the Bureau of Ocean Energy Management (the “BOEM”) can require supplemental bonding from operators for decommissioning, plugging, and abandonment liabilities if certain financial strength and reliability criteria are not met. We anticipate that we will provide to the BOEM additional supplemental bonding in the near future. We are working with the BOEM on amounts of additional supplemental bonding and the timing of when such bonds might be put in place. Total supplemental bonding requirements could be up to $250 million, but we believe the ultimate requirement will be less. We believe such additional bonds will be available in the market.

Weak commodity prices in the first half of 2015 have had a significant impact on our business, as discussed in the section titled *Six Months Ended June 30, 2015 Compared to Six Months Ended June 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 positive side, 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 June 30,				Six Months Ended June 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	$ 108,079	$ 185,424	$ (77,345)	(41.7)%	$ 189,606	$ 356,129	$ (166,523)	(46.8)%
NGLs	7,831	20,566	(12,735)	(61.9)%	15,277	40,588	(25,311)	(62.4)%
Natural gas	31,485	56,105	(24,620)	(43.9)%	68,660	119,442	(50,782)	(42.5)%
Other	1,671	899	772	85.9%	3,430	1,351	2,079	153.9%
Total revenues	149,066	262,994	(113,928)	(43.3)%	276,973	517,510	(240,537)	(46.5)%
Operating costs and expenses:								
Lease operating expenses	45,130	61,765	(16,635)	(26.9)%	98,461	117,384	(18,923)	(16.1)%
Production taxes	1,000	1,842	(842)	(45.7)%	1,637	3,834	(2,197)	(57.3)%
Gathering and transportation	4,793	3,985	808	20.3%	9,617	9,281	336	3.6%
Depreciation, depletion, amortization and accretion	103,342	128,236	(24,894)	(19.4)%	228,809	251,542	(22,733)	(9.0)%
Ceiling test write-down of oil and natural gas properties	252,772	—	252,772	NM	513,162	—	513,162	NM
General and administrative expenses	19,757	19,682	75	0.4%	40,523	43,270	(2,747)	(6.3)%
Derivative loss	1,078	13,079	(12,001)	NM	1,078	20,571	(19,493)	NM
Total costs and expenses	427,872	228,589	199,283	87.2%	893,287	445,882	447,405	100.3%
Operating income (loss)	(278,806)	34,405	(313,211)	NM	(616,314)	71,628	(687,942)	NM
Interest expense, net of amounts capitalized	24,092	19,295	4,797	24.9%	45,255	38,681	6,574	17.0%
Debt issuance costs write-off and other, net	1,685	—	1,685	NM	1,683	—	1,683	NM
Income (loss) before income tax expense (benefit)	(304,583)	15,110	(319,693)	NM	(663,252)	32,947	(696,199)	NM
Income tax expense (benefit)	(44,134)	5,273	(49,407)	NM	(147,708)	11,921	(159,629)	NM
Net income (loss)	$ (260,449)	$ 9,837	$ (270,286)	NM	$ (515,544)	$ 21,026	$ (536,570)	NM
Basic and diluted earnings (loss) per common share	$ (3.43)	$ 0.13	$ (3.56)	NM	$ (6.79)	$ 0.28	$ (7.07)	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 June 30, 2015	Three Months Ended June 30, 2014	Change	% (3)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Change	% (3)
Operating: (1) (2)								
Net sales:								
Oil (MBbls)	1,909	1,856	53	2.9%	3,803	3,588	215	6.0%
NGLs (MBbls)	408	514	(106)	(20.6)%	851	1,038	(187)	(18.0)%
Natural gas (MMcf)	11,486	12,150	(664)	(5.5)%	23,835	24,768	(933)	(3.8)%
Total oil equivalent (MBoe)	4,231	4,395	(164)	(3.7)%	8,627	8,754	(127)	(1.5)%
Total natural gas equivalents (MMcfe)	25,388	26,371	(983)	(3.7)%	51,760	52,521	(761)	(1.4)%
Average daily equivalent sales (Boe/day)	46,497	48,299	(1,802)	(3.7)%	47,661	48,362	(701)	(1.4)%
Average daily equivalent sales (Mcfe/day)	278,984	289,792	(10,808)	(3.7)%	285,965	290,174	(4,209)	(1.5)%
Average realized sales prices:								
Oil ($/Bbl)	$ 56.63	$ 99.92	$ (43.29)	(43.3)%	$ 49.86	$ 99.26	$ (49.40)	(49.8)%
NGLs ($/Bbl)	19.18	39.98	(20.80)	(52.0)%	17.94	39.11	(21.17)	(54.1)%
Natural gas ($/Mcf)	2.74	4.62	(1.88)	(40.7)%	2.88	4.82	(1.94)	(40.2)%
Oil equivalent ($/Boe)	34.83	59.63	(24.80)	(41.6)%	31.71	58.97	(27.26)	(46.2)%
Natural gas equivalent ($/Mcfe)	5.81	9.94	(4.13)	(41.5)%	5.28	9.83	(4.55)	(46.3)%
Average per Boe ($/Boe):								
Lease operating expenses	$ 10.67	$ 14.05	$ (3.38)	(24.1)%	$ 11.41	$ 13.41	$ (2.00)	(14.9)%
Gathering and transportation	1.13	0.91	0.22	24.2%	1.11	1.06	0.05	4.7%
Production costs	11.80	14.96	(3.16)	(21.1)%	12.52	14.47	(1.95)	(13.5)%
Production taxes	0.24	0.42	(0.18)	(42.9)%	0.19	0.44	(0.25)	(56.8)%
DD&A	24.42	29.18	(4.76)	(16.3)%	26.52	28.73	(2.21)	(7.7)%
General and administrative expenses	4.67	4.48	0.19	4.2%	4.70	4.94	(0.24)	(4.9)%
	$ 41.13	$ 49.04	$ (7.91)	(16.1)%	$ 43.93	$ 48.58	$ (4.65)	(9.6)%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$ 1.78	$ 2.34	$ (0.56)	(23.9)%	$ 1.90	$ 2.23	$ (0.33)	(14.8)%
Gathering and transportation	0.19	0.15	0.04	26.7%	0.19	0.18	0.01	5.6%
Production costs	1.97	2.49	(0.52)	(20.9)%	2.09	2.41	(0.32)	(13.3)%
Production taxes	0.04	0.07	(0.03)	(42.9)%	0.03	0.07	(0.04)	(57.1)%
DD&A	4.07	4.86	(0.79)	(16.3)%	4.42	4.79	(0.37)	(7.7)%
General and administrative expenses	0.78	0.75	0.03	4.0%	0.78	0.82	(0.04)	(4.9)%
	$ 6.86	$ 8.17	$ (1.31)	(16.0)%	$ 7.32	$ 8.09	$ (0.77)	(9.5)%

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	Change	%	2015	2014	Change	%
Wells drilled (gross):								
Offshore	2	2	—	—	4	3	1	33.3 %
Onshore	1	10	(9)	(90.0)%	5	22	(17)	(77.3)%
Productive wells drilled (gross)								
Offshore	2	2	—	—	4	3	1	33.3 %
Onshore	1	10	(9)	(90.0)%	5	22	(17)	(77.3)%

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

Revenues. Total revenues decreased $113.9 million, or 43.3%, to $149.1 million for the second quarter of 2015 as compared to the second quarter of 2014. Oil revenues decreased $77.3 million, or 41.7%, NGLs revenues decreased $12.7 million, or 61.9%, natural gas revenues decreased $24.6 million, or 43.9%, while other revenues increased $0.7 million. The decrease in oil revenues was attributable to a 43.3% decrease in the average realized sales price to $56.63 per barrel for the second quarter of 2015 from $99.92 per barrel for the second quarter of 2014, partially offset by a 2.9% increase in sales volumes. The decrease in NGLs revenues was attributable to a 52.0% decrease in the average realized sales price to $19.18 per barrel for the second quarter of 2015 from $39.98 per barrel for the second quarter of 2014 and a decrease of 20.6% in sales volumes. The decrease in natural gas revenues resulted from a 40.7% decrease in the average realized natural gas sales price to $2.74 per Mcf for the second quarter of 2015 from $4.62 per Mcf for the second quarter of 2014 and from a decrease of 5.5% in sales volumes. We experienced increases in production from acquisitions at the Neptune field and the Fairway field, the Ship Shoal 349 field (Mahogany) and from Mississippi Canyon 506 field (Wrigley), which had deferred production in the second quarter of 2014 as a result of maintenance at the host platform. 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 were 0.7 million barrels of oil equivalent (“MMBoe”) during the second quarter of 2015 which occurred at multiple locations. During the second quarter of 2014, we experienced production deferrals of 0.6 MMBoe.

Revenues from oil and liquids as a percent of our total revenues were 77.8% for the second quarter of 2015 compared to 78.3% for the second quarter of 2014. Our average realized NGLs sales price as a percent of our average realized oil sales price decreased to 33.9% for the second quarter of 2015 compared to 40.0% for the second quarter of 2014.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workover and maintenance expenses on our facilities, as well as hurricane related expenses and insurance reimbursements, decreased $16.6 million to $45.1 million, or 26.9%, in the second quarter of 2015 compared to the second quarter of 2014. On a per Boe basis, lease operating expenses decreased to $10.67 per Boe in the second quarter of 2015 compared to $14.05 per Boe in the second quarter of 2014. On a component basis, base lease operating expenses decreased $11.2 million primarily due to decreased costs from service providers, lease terminations and less downhole onshore well work, partially offset by lower production handling fees and costs related to the acquisition of the Woodside Properties (Neptune field) during the second quarter of 2014. Facilities maintenance expenses decreased $4.9 million due to reduced activity at multiple offshore locations. Insurance premiums decreased $0.9 million and hurricane related insurance reimbursements increased $0.1 million. Partially offsetting was an increase in workover expenses of $0.6 million primarily due to offshore activity at Eugene Island 217 and Ship Shoal 349 (Mahogany), partially offset by lower onshore activity.

Production taxes. Production taxes decreased $0.8 million to $1.0 million for the second quarter of 2015 compared to the second quarter of 2014. The decrease is primarily due to lower revenues for onshore operations and the Fairway 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 increased $0.8 million to $4.8 million for the second quarter of 2015 compared to the second quarter of 2014.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $24.42 per Boe for the second quarter of 2015 from $29.18 per Boe for the second quarter of 2014. On a nominal basis, DD&A decreased to $103.3 million for the second quarter of 2015 from $128.2 million for the second quarter of 2014 due to decreased production and a decrease in the DD&A per Boe rate. The DD&A per Boe rate decreased primarily due to the ceiling test write-down recorded in the first quarter of 2015 and lower capital expenditures in relation DD&A expense, which lowers the full-cost pool subject to DD&A. The ceiling test write-down recorded in the second 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 from reduced service company rates.

Ceiling test write-down of oil and natural gas properties. For the second quarter of 2015, we recorded a non-cash ceiling test write-down of $252.8 million as the book value of our oil and natural gas properties exceeded the ceiling test limit. 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 incurred in the second 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 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 was essentially flat for the second quarter of 2015 compared to the second quarter of 2014. Lower billings to third-parties for joint venture arrangements and recording a contingent assessment provision were offset by lower incentive compensation expenses and lower contractor expenses. G&A on a per Boe basis was $4.67 per Boe for the second quarter of 2015 compared to $4.48 per Boe for the second quarter of 2014.

Derivative loss. For the second quarter of 2015, there was a $1.0 million derivative loss recorded for open 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 second quarter of 2014, derivative net losses were $13.1 million related to derivative contracts for crude oil.

Interest expense. Interest expense incurred for the second quarter of 2015 and 2014 was $26.1 million and $21.5 million, respectively. The increase was primarily attributable to the issuance of the 9.00% Term Loan in May 2015, which carries a higher interest rate compared to funds borrowed on our revolving bank credit facility. In addition, the outstanding average balance on our revolving bank credit facility was higher in the second quarter of 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 second quarter of 2015 and 2014, $2.0 million and $2.2 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties.

Debt issuance costs write-off and other, net. 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 revolving bank credit facility. Partially offsetting was a gain of $0.3 million from the sale of an interest in an airplane.

Income tax expense. Our income tax benefit for the second quarter of 2015 was $44.1 million compared to income tax expense of $5.3 million for the second quarter of 2014, attributable to a pre-tax loss for the second quarter of 2015 compared to pre-tax income for the second quarter of 2014. The income tax benefit is partially attributable to recording a ceiling test write-down of $252.8 million in the second quarter of 2015. Our effective tax rate was 14.5% and differs from the federal statutory rate of 35% primarily due to recording a valuation allowance of $62.9 million during the second quarter of 2015 related to federal deferred tax assets and net operating losses. 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 in the future. Our effective tax rate for the second quarter of 2014 was 34.9% and differed slightly from the federal statutory rate of 35.0% 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.

Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014

Revenues. Total revenues decreased $240.5 million, or 46.5%, to $277.0 million for the first half of 2015 as compared to the first half of 2014. Oil revenues decreased $166.5 million, or 46.8%, NGLs revenues decreased $25.3 million, or 62.4%, natural gas revenues decreased $50.8 million, or 42.5%, and other revenues increased $2.1 million. The decrease in oil revenues was attributable to a 49.8% decrease in the average realized sales price to $49.86 per barrel for the first half of 2015 from $99.26 per barrel for the first half of 2014, partially offset by a 6.0% increase in sales volumes. The decrease in NGLs revenues was attributable to a 54.1% decrease in the average realized sales price to $17.94 per barrel for the first half of 2015 from $39.11 per barrel for the first half of 2014 and a decrease of 18.0% in sales volumes. The decrease in natural gas revenues resulted from a 40.2% decrease in the average realized natural gas sales price to $2.88 per Mcf for the first half of 2015 from $4.82 per Mcf for the first half of 2014 and from a decrease of 3.8% in sales volumes. We experienced increases in production from acquisitions at the Neptune field and the Fairway field, the Ship Shoal 349 field (Mahogany) and from Mississippi Canyon 506 field (Wrigley), which had deferred production in the first half of 2014 as a result of maintenance at the host platform. 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 were 1.2 MMBoe during both the first half of 2015 and the first half of 2014, which occurred at multiple locations.

Revenues from oil and liquids as a percent of our total revenues were 74.0% for the first half of 2015 compared to 76.7% for the first half of 2014 period. Our average realized NGLs sales price as a percent of our average realized oil sales price decreased to 36.0% for the first half of 2015 compared to 39.4% for the first half of 2014 period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workover and maintenance expenses on our facilities, as well as hurricane related expenses and insurance reimbursements, decreased $18.9 million to $98.5 million, or 16.1%, in the first half of 2015 compared to the first half of 2014. On a per Boe basis, lease operating expenses decreased to $11.41 per Boe in the first half of 2015 compared to $13.41 per Boe in the first half of 2014. On a component basis, base lease operating expenses decreased $9.1 million primarily due to decreased costs from service providers, lease terminations and less downhole onshore well work, partially offset by lower production handling fees and costs related to the acquisition of the Woodside Properties (Neptune field) during the second quarter of 2014 and the increase in ownership at Fairway during the third quarter of 2014. Facilities maintenance expenses decreased $7.8 million due to reduced activity at multiple offshore locations. Workover expenses decreased $1.6 million primarily due to reductions in onshore activity. Insurance premiums decreased $0.7 million and hurricane related insurance reimbursements decreased $0.3 million.

Production taxes. Production taxes decreased $2.2 million to $1.6 million for the first half of 2015 compared to the first half of 2014. The decrease is primarily due to lower revenues for onshore operations and the Fairway 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 increased $0.3 million to $9.6 million for the first half of 2015 compared to the first half of 2014.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $26.52 per Boe for the first half of 2015 from $28.73 per Boe for the first half of 2014. On a nominal basis, DD&A decreased to $228.8 million for the first half of 2015 from $251.5 million for the first half of 2014 due to decreased production and a decrease in the DD&A per Boe rate. The DD&A per Boe rate decreased primarily due to the ceiling test write-down recorded in the first quarter of 2015 and lower capital expenditures in relation DD&A expense, which lowers the full-cost pool subject to DD&A. The ceiling test write-down recorded in the second 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 from reduced service company rates.

Ceiling test write-down of oil and natural gas properties. For the first half of 2015, we recorded a non-cash ceiling test write-down of $513.2 million as the book value of our oil and natural gas properties exceeded the ceiling test limit. 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 incurred in the first half 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 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 $40.5 million for the first half of 2015 from $43.3 million for the first half of 2014 primarily due to lower incentive compensation expenses, partially offset by lower billings to third-parties for joint venture arrangements and from recording a contingent assessment provision. G&A on a per Boe basis was $4.70 per Boe for the first half of 2015 compared to $4.94 per Boe for the first half of 2014.

Derivative loss. For the first half of 2015, there was a $1.0 million derivative loss recorded for open derivative contracts for crude oil and naturalgas. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015. For the first half of 2014, derivative net losses were $20.6 million related to derivative contracts for crude oil.

Interest expense. Interest expense incurred for the first half of 2015 and 2014 was $49.1 million and $42.9 million, respectively. The increase was primarily attributable to the issuance of the 9.00% Term Loan in May 2015, which carries a higher interest rate compared to funds borrowed on our revolving bank credit facility. In addition, the outstanding average balance on our revolving bank credit facility was higher in the first half of 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 first half of 2015 and 2014, $3.8 million and $4.2 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.

Debt issuance costs write-off and other, net. 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 revolving bank credit facility. Partially offsetting was a gain of $0.3 million from the sale of an interest in an airplane.

Income tax expense. Our income tax benefit for the first half of 2015 was $147.7 million compared to income tax expense of $11.9 million for the first half of 2014, attributable to a pre-tax loss for the first half of 2015 compared to pre-tax income for the first half of 2014. Our effective tax rate was 22.3% and differs from the federal statutory rate of 35% primarily due to recording a valuation allowance of $85.4 million during the first half of 2015 related to federal deferred tax assets and net operating losses. 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 in the future. Our effective tax rate for the first half of 2014 was 36.2% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes. 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 and make related interest payments. 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 first half of 2015 was $30.1 million compared to $271.1 million for the first half of 2014. Cash flows from operating activities, before changes in working capital and ARO settlements, were $87.9 million in the first half of 2015, a decrease of $210.8 million compared to the $298.8 million generated during the first half of 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 partially offset by lower operating expenses. Our combined average realized sales price per Boe decreased 46.2%. Combined production of oil, NGLs and natural gas on a Boe basis decreased 1.5% for the first half of 2015 compared to the first half of 2014.

The changes in working capital and ARO settlements decreased operating cash flows by $57.9 million in the first half of 2015 and decreased operating cash flows by $27.7 million in the first half of 2014, resulting in a difference of $30.2 million. The difference was due to changes in accounts payable, accrued liabilities and, partially offset by changes in receivables, ARO settlements, prepaid assets and other assets.

Net cash used in investing activities during the first half of 2015 and 2014 was $151.7 million and $267.8 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. There were no acquisitions of significance during the first half of 2015. Capital expenditures for the first half of 2015 represent approximately 75% of our annual budget for 2015, which is in line with our expectations of the timing of our capital expenditures. During the first half of 2014, expenditures for an acquisition were $53.4 million for the Woodside Properties.

Net cash provided by financing activities for the first half of 2015 and 2014 was $103.6 million and $4.8 million, respectively. Net borrowings of long-term debt increased $113.0 million in the first half of 2015 compared to year end 2014. The net cash provided for the first half of 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. Partially offsetting were net increased borrowings on our revolving bank credit facility, excluding the pay down from the debt issuance. The net cash provided for the first half of 2014 was attributable to net borrowings of $20.0 million on our revolving bank credit facility and partially offset by dividend payments of $15.1 million.

At June 30, 2015, we had a cash balance of $5.7 million and $239.4 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $500.0 million as of June 30, 2015.

Credit Agreement and long-term debt. At June 30, 2015 and December 31, 2014, $260.0 million and $447.0 million, respectively, were outstanding under our revolving bank credit facility. During the six months ended June 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 million 9.00% Term Loan, which was outstanding as of June 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 June 30, 2015 and December 31, 2014, $900.0 million in aggregate principal amount of our 8.50% Senior Notes was outstanding. We believe that cash provided by operations, borrowings available under our revolving bank credit facility 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. Conversely, divestitures could provide additional liquidity to fund acquisitions or capital expenditures.

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. See *Financial Statements - Note 5 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for a summary of the financial covenants. 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 June 30, 2015.

If commodity prices decline or remain similar to our average prices realized in the first half of 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, and c) reductions in our proved reserves. 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 market conditions recover or stabilize. Realization of any of these events would depend on the longevity and severity of such price weakness.

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 the derivative contracts relate to approximately 25% of projected production for the second half 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 $161.2 million has been collected through June 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. 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.

All of our Gulf of Mexico properties with estimated future net revenues are covered under our current insurance policies for named windstorm damage. The risk exposure varies per property and we have exposure for applicable retentions, co-insurance amounts and coverage limits.

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.

Although we were able to renew our general, excess liability policies and Energy Package in May and June of 2015, 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, and the results of our exploration and development activities. The following table presents our capital expenditures for exploration, development and other leasehold costs and acquisitions:

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(In thousands)	
Acquisition of Woodside Properties (1)	$ 161	$ 53,363
Exploration (2)	40,235	86,793
Development (2)	99,149	104,685
Seismic, capitalized interest, and other	11,449	21,202
Acquisitions and investments in oil and gas property/equipment	$ 150,994	$ 266,043

(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 geographically:

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(In thousands)	
Conventional shelf	$ 9,321	$ 62,452
Deepwater	117,748	40,615
Deep shelf	—	21,828
Onshore	12,315	66,583
Exploration and development capital expenditures	$ 139,384	$ 191,478

Our capital expenditures for the first half of 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 first half of 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:

	Six Months Ended June 30, 2015		2014	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	—	—	—	—
Non-productive	—	—	—	—
Onshore wells:				
Productive	3	2.3	12	11.3
Non-productive	—	—	—	—
Total development wells	3	2.3	12	11.3
Exploration wells:				
Offshore wells:				
Productive	4	0.7	3	2.2
Non-productive	—	—	—	—
Onshore wells:				
Productive	2	1.9	10	9.9
Non-productive	—	—	—	—
Total exploration wells	6	2.6	13	12.1
Total wells	9	4.9	25	23.4

Exploration activities. During the first half of 2015, the four offshore exploration wells completed were the #1 and #2 wells at Mississippi Canyon 782 (Dantzler) and the #6 and #7 wells at Mississippi Canyon 538 (Medusa). First production is expected in late 2015 at Dantzler and first production occurred late in the second quarter of 2015 at Medusa for these recently completed wells. During the first half of 2015, three of the onshore wells completed were horizontal wells and four of the five onshore wells completed in 2015 were producing in July 2015. Subsequent to June 30, 2015, we had one offshore well completed, one offshore well being drilled, one offshore well awaiting completion, six onshore wells awaiting completion and two onshore wells being evaluated. During the first half of 2014, the completion operations on the Mississippi Canyon 698 (Big Bend) well were finalized, with first production expected in late 2015.

Acquisitions and funding. We intend to continue to pursue acquisitions and joint venture opportunities during 2015 and beyond 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. During the first half of 2015, we did not have any divestitures of significance.

Capital Expenditure Budget for 2015. Our current capital expenditure budget for 2015 is $200 million, not including any potential acquisitions. 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 July 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 and potential 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 first half of 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 $516.4 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. Pursuant to the Credit Agreement, the regular quarterly dividend is suspended until June 2016, and may be suspended further depending on certain financial covenants. See *Financial Statements - Note 5 – Long-Term Debt* and *Note 10 – Dividends* under Part I, Item 1 of this Form 10-Q for additional information.

Capital markets and impact on liquidity. As previously discussed, we entered into a 9.00% Term Loan during the second quarter of 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 through June 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* and *Note 5 – Long-Term* under Part I, Item 1 of this Form 10-Q. As of June 30, 2015, drilling rig commitments were approximately $6.6 million compared to $12.6 million as of December 31, 2014. The current drilling rig commitments expire within one year from June 30, 2015. Except for scheduled utilization, other contractual obligations as of June 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 six months ended June 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 June 30, 2015, we had open derivative contracts related to a portion of estimated production for the second half 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 June 30, 2015, we had $260.0 million outstanding on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the rates for the LIBOR and the margin, which ranges from 2.25% to 3.25% depending on the amount outstanding. As of June 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. Based on that evaluation, our CEO and CFO have each concluded that as of June 30, 2015 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended June 30, 2015, there was no change in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, *Financial Statements – Note 11 – Contingencies*, 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, except as set forth below.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater gathered from our drilling and production activities, which could have a material adverse effect on our business.

We dispose of large volumes of wastewater generated by our Permian Basin drilling and production activities. This wastewater is frequently co-produced with oil and natural gas and is very salty. The most common method for disposing of this "produced water" is by injection into deep disposal wells, pursuant to permits issued by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements. A few recent studies have indicated that the injection of large volumes of produced water into certain underground formations may induce low-level seismic activity that can on occasion be felt by persons on the ground surface. In response public concerns associated with these ground tremors, regulators in some states have begun to take actions to prevent injection wells from inducing excessive seismicity. For example, in October 2014, the Texas Railroad Commission ("TRC") published a new rule governing permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permit holder or applicant fails to demonstrate that the injected fluids will be confined to the disposal zone or if scientific data indicates the disposal well is likely to contribute to seismic activity, then the TRC may modify or suspend an existing permit or deny the application for a new permit. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of wastewater produced by our drilling and production activities could increase our costs of disposing of produced water and have a material adverse effect on our business, financial condition and results of operations.

Requirements imposed by the Bureau of Ocean Energy Management related to the decommissioning, plugging, and abandonment of offshore facilities could significantly impact the cost of operating our business.

As discussed in this risk factor in Part I, Item 1A, *Risk Factors,* in our Annual Report on Form 10-K for the year ended December 31, 2014, the BOEM can require supplemental bonding from operators for decommissioning, plugging, and abandonment liabilities if financial strength and reliability criteria are not met. We anticipate that we will be required by the BOEM to provided additional supplemental bonding in the near future. We are working with the BOEM on amounts of additional supplemental bonding and the timing of when such bonds might be put in place. Total supplemental bonding requirements could be up to $250 million, but we believe the ultimate requirement will be less. We believe such additional bonds will be available in the market. The failure to obtain any additional bonds following a determination that they are required by BOEM could adversely affect our ability to operate in the Gulf of Mexico.

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 August 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
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))
10.1	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 23, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent, and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed April 27, 2015 (File No. 001-32414))
10.2	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of May 8, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.3	$300,000,000 Term Loan Agreement, dated May 11, 2015, by and among W&T Offshore, Inc., Morgan Stanley Senior Funding, Inc., as administrative agent and collateral trustee, and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
10.4	Intercreditor Agreement, dated May 11, 2015, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as priority lien agent, Morgan Stanley Senior Funding, Inc., as second lien collateral trustee, and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed May 14, 2015 (File No. 001-32414))
31.1*	Section 302 Certification of Chief Executive Officer.
31.2*	Section 302 Certification of Chief Financial Officer.
32.1**	Section 906 Certification of Chief Executive Officer and Chief Financial Officer.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith.
** Furnished herewith.

Exhibit 31.1

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

I, Tracy W. Krohn, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2015

/s/ Tracy W. Krohn

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

Exhibit 31.2

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

I, John D. Gibbons, certify that:

1. I have reviewed this quarterly report on Form 10-Q of W&T Offshore, Inc. (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2015

/s/ John D. Gibbons

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

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2015 fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act and that information contained in such Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 6, 2015

/s/ Tracy W. Krohn

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

Date: August 6, 2015

/s/ John D. Gibbons

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