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

Form 10-Q

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

For the quarterly period ended September 30, 2014

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 November 4, 2014, there were 75,656,558 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

	September 30, 2014	December 31, 2013
	(In thousands, except per share data)	
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 17,220	$ 15,800
Receivables:		
Oil and natural gas sales	97,688	96,752
Joint interest and other	32,785	27,984
Income taxes	120	3,120
Total receivables	130,593	127,856
Prepaid expenses and other assets	32,555	29,946
Total current assets	180,368	173,602
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $123,903 at September 30, 2014 and $116,612 at December 31, 2013 were excluded from amortization)	7,865,702	7,339,097
Furniture, fixtures and other	22,128	21,431
Total property and equipment	7,887,830	7,360,528
Less accumulated depreciation, depletion and amortization	5,449,545	5,084,704
Net property and equipment	2,438,285	2,275,824
Restricted deposits for asset retirement obligations	15,382	37,421
Other assets	17,989	20,455
Total assets	$ 2,652,024	$ 2,507,302
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 159,621	$ 145,212
Undistributed oil and natural gas proceeds	37,821	42,107
Asset retirement obligations	115,722	77,785
Accrued liabilities	39,030	28,000
Total current liabilities	352,194	293,104
Long-term debt, less current maturities	1,260,665	1,205,421
Asset retirement obligations, less current portion	288,280	276,637
Deferred income taxes	187,057	178,142
Other liabilities	13,634	13,388
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at September 30, 2014 and December 31, 2013	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,525,731 issued and 75,656,558 outstanding at September 30, 2014; 78,460,872 issued and 75,591,699 outstanding at December 31, 2013	1	1
Additional paid-in capital	414,430	403,564
Retained earnings	159,930	161,212
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	550,194	540,610
Total liabilities and shareholders' equity	$ 2,652,024	$ 2,507,302

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In thousands except per share data) (Unaudited)			
Revenues	$ 234,521	$ 244,555	$ 752,031	$ 739,160
Operating costs and expenses:				
Lease operating expenses	71,732	67,346	189,116	194,935
Production taxes	1,794	1,807	5,628	5,375
Gathering and transportation	4,115	3,611	13,396	12,663
Depreciation, depletion, amortization and accretion	128,671	104,143	380,213	312,911
General and administrative expenses	21,007	20,024	64,277	60,979
Derivative (gain) loss	(13,781)	15,659	6,790	6,186
Total costs and expenses	213,538	212,590	659,420	593,049
Operating income	20,983	31,965	92,611	146,111
Interest expense:				
Incurred	21,783	21,373	64,703	64,157
Capitalized	(2,191)	(2,573)	(6,422)	(7,537)
Other income	197	9,062	205	9,075
Income before income tax expense	1,588	22,227	34,535	98,566
Income tax expense	904	8,033	12,825	35,358
Net income	$ 684	$ 14,194	$ 21,710	$ 63,208
Basic and diluted earnings per common share	$ 0.01	$ 0.19	$ 0.28	$ 0.83
Dividends declared per common share	$ 0.10	$ 0.09	$ 0.30	$ 0.26

See Notes to Condensed Consolidated Financial Statements.

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

	Common Stock Outstanding		Additional Paid-In	Retained	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	Earnings	Shares	Value	Equity
				(In thousands) (Unaudited)			
Balances at December 31, 2013	75,592	$ 1	$ 403,564	$ 161,212	2,869	$ (24,167)	$ 540,610
Cash dividends	—	—	—	(22,695)	—	—	(22,695)
Share-based compensation	65	—	11,398	—	—	—	11,398
Other	—	—	(532)	(297)	—	—	(829)
Net income	—	—	—	21,710	—	—	21,710
Balances at September 30, 2014	75,657	$ 1	$ 414,430	$ 159,930	2,869	$ (24,167)	$ 550,194

See Notes to Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(In thousands) (Unaudited)	
Operating activities:		
Net income	$ 21,710	$ 63,208
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	380,213	312,911
Amortization of debt issuance costs and premium	537	1,366
Share-based compensation	11,398	8,457
Derivative loss	6,790	6,186
Cash payments on derivative settlements	(18,543)	(6,855)
Deferred income taxes	12,825	31,581
Changes in operating assets and liabilities:		
Oil and natural gas receivables	(936)	12,511
Joint interest and other receivables	1,890	30,064
Income taxes	2,884	53,433
Prepaid expenses and other assets	21,228	(10,815)
Asset retirement obligation settlements	(42,011)	(59,188)
Accounts payable, accrued liabilities and other	26,960	32,974
Net cash provided by operating activities	424,945	475,833
Investing activities:		
Acquisition of property interest in oil and natural gas properties	(71,515)	—
Investment in oil and natural gas properties and equipment	(383,953)	(423,092)
Proceeds from sales of assets and other, net	—	21,011
Change in restricted cash	—	(16,459)
Purchases of furniture, fixtures and other	(2,181)	(1,327)
Net cash used in investing activities	(457,649)	(419,867)
Financing activities:		
Borrowings of long-term debt - revolving bank credit facility	378,000	335,000
Repayments of long-term debt - revolving bank credit facility	(321,000)	(368,000)
Dividends to shareholders	(22,695)	(19,570)
Other	(181)	(414)
Net cash provided by (used in) financing activities	34,124	(52,984)
Increase in cash and cash equivalents	1,420	2,982
Cash and cash equivalents, beginning of period	15,800	12,245
Cash and cash equivalents, end of period	$ 17,220	$ 15,227

See Notes to Condensed Consolidated Financial Statements.

1. Basis of Presentation

Operations. W&T Offshore, Inc. and subsidiaries, referred to herein as "W&T," "we," "us" 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 our 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, 2013.

Reclassifications. Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation. The change in *Insurance receivables* was combined with the change in *Joint interest and other receivables* on the Condensed Consolidated Statements of Cash Flows.

Transactions between Entities Under Common Control. The prior period financial information presented in Note 13, *Supplemental Guarantor Information*, has been retrospectively adjusted due to transactions between entities under common control, as required under authoritative guidance.

Allowance for Doubtful Accounts. Historically, we have had only minor issues collecting our receivables. For situations where collectability is uncertain, and for joint-interest arrangements where the ability to recover receivables from future net revenues is uncertain, we establish an allowance for doubtful accounts. As of September 30, 2014, we had an immaterial amount recorded in the allowance for doubtful accounts. No allowance for doubtful accounts was recorded at December 31, 2013.

Other Income. For the three and nine months ended September 30, 2013, the amount reported consisted primarily of $9.2 million received in conjunction with a payment to the Company for an option exercised by a counterparty. Partially offsetting were related third-party expenses of $0.1 million. The net amount was included in net cash flows from investing activities within the line, *Proceeds from sales of assets and other, net* on the Condensed Consolidated Statements of Cash Flows.

Income Taxes. Due to the recent volatility in crude oil prices and its impact on future results, the Company changed the method of recording income taxes from the annualized effective tax rate method to the year-to-date method for the three and nine months ended September 30, 2014. For the three and nine months ended September 30, 2013, the Company used the annualized effective tax method.

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.

Adjustment Related to Additional Volumes. In January 2014, we identified that we had been receiving an erroneous conversion factor from a third party that had the effect of understating natural gas production at our Viosca Knoll 783 field (Tahoe). The incorrect conversion factor had been used on all natural gas production from the field since we acquired it in 2011. The effect of using this incorrect conversion factor did not affect revenues, operating cash flows or royalty payments to the federal government but did impact reported natural gas production and the calculation of depletion expense. We performed an analysis of the information, assessing both quantitative and qualitative factors, and determined that the impact on our net income reported for quarters in 2013, as well as the impact to our earnings trend, was not material to the previously reported results, thus the adjustment was recognized in the fourth quarter of 2013. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the third quarter of 2013 were: an increase in natural gas production volumes of 237 million cubic feet ("MMcf") (with no corresponding increase in revenue); an increase to depreciation, depletion, amortization and accretion expense ("DD&A") of $0.6 million; and a decrease to net income of $0.4 million. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the nine months ended September 30, 2013 were: an increase in natural gas production volumes of 754 MMcf (with no corresponding increase in revenue); an increase to DD&A of $2.1 million; and a decrease to net income of $1.4 million.

Recent Accounting Developments. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09 ("ASU 2014-09"), *Summary and Amendments That Create Revenue from Contracts and Customers (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, 2016. 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 2017.

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.

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 asset retirement obligations ("ARO"). The purchase price is expected to be finalized by the first quarter of 2015. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

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

Cash consideration:		
Evaluated properties including equipment	$	18,152
Non-cash consideration:		
Asset retirement obligations - non-current		6,124
Total consideration	$	24,276

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.

The acquisition was not included in our consolidated results until the property transfer date, which occurred in September 2014 and the incremental revenue and operating expenses were immaterial for the three and nine months periods ended September 30, 2014. Unaudited pro forma information is not presented as the pro forma information is not materially different from the reported results for the 2014 and 2013 time periods presented.

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. The purchase price is expected to be finalized during 2014. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand.

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

Cash consideration:		
Evaluated properties including equipment	$	50,703
Unevaluated properties		2,660
Sub-total cash consideration		53,363
Non-cash consideration:		
Asset retirement obligations - current		782
Asset retirement obligations - non-current		10,543
Sub-total non-cash consideration		11,325
Total consideration	$	64,688

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 Acquisition — Revenues, Net Income and Pro Forma Financial Information

The Woodside Properties were not included in our consolidated results until the property transfer date, which occurred in May 2014. For the three months ended September 30, 2014, the Woodside Properties accounted for $12.5 million of revenues, $1.7 million of direct operating expenses, $4.3 million of DD&A and $2.3 million of income taxes, resulting in $4.2 million of net income. For the nine months ended September 30, 2014, the Woodside Properties accounted for $19.4 million of revenues, $2.4 million of direct operating expenses, $6.5 million of DD&A and $3.7 million of income taxes, resulting in $6.8 million of net income. Also, we incurred $0.1 million of expenses associated with acquisition and transition activities related to the acquisition of the Woodside Properties for the nine months ended September 30, 2014. 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, the unaudited pro forma financial information was computed as if the acquisition of the Woodside Properties 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, natural gas liquids ("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 (in thousands, except earnings per share):

	Three Months Ended September 30,	Nine Months Ended September 30,	
	2013	2014	2013
Revenue	$ 260,989	$ 774,918	$ 789,280
Net income	19,860	27,901	80,291
Basic and diluted earnings per common share	0.26	0.36	1.06

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):

	Three Months Ended September 30,	Nine Months Ended September 30,	
	2013	2014	2013
Revenues (a)	$ 16,434	$ 22,887	$ 50,120
Direct operating expenses (a)	2,206	4,417	7,195
DD&A (b)	5,021	8,248	15,261
G&A (c)	200	400	600
Interest expense (d)	240	320	720
Capitalized interest (e)	50	(22)	63
Income taxes expense (f)	3,051	3,333	9,198

The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Woodside Properties were derived from the historical financial records of Woodside.

(b) 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.

(c) Estimated insurance costs related to the Woodside Properties.

(d) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $53.4 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.

(e) 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.

(f) 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.

2013 Acquisition

On October 17, 2013, W&T Offshore, Inc. entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Callon Petroleum Operating Company ("Callon"). Pursuant to the purchase and sale agreement, transfers of certain properties that had no preferential rights were consummated on November 5, 2013 and transfers of certain properties subject to preferential rights, of which third-parties declined to exercise their preferential rights, were consummated on December 4, 2013. The properties acquired from Callon (the "Callon Properties") consist of a 15% working interest in the Medusa field (deepwater Mississippi Canyon blocks 582 and 583), interest in associated production facilities and various interests in other non-operated fields. All of the Callon Properties are located in the Gulf of Mexico. The effective date of the transaction was July 1, 2013. The transaction included customary adjustments for the effective date, certain closing adjustments and we assumed the related ARO. An upward net purchase price adjustment of $0.6 million was recorded during the nine months ended September 30, 2014 and the purchase price was finalized in the second quarter of 2014. 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 Callon Properties (in thousands):

Cash consideration:		
Evaluated properties including equipment	$	73,752
Unevaluated properties		9,248
Sub-total cash consideration		83,000
Non-cash consideration:		
Asset retirement obligations - current		90
Asset retirement obligations - non-current		4,143
Sub-total non-cash consideration		4,233
Total consideration	$	87,233

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 Callon Properties acquisition.

2013 Acquisition — Revenues, Net Income and Pro Forma Financial Information

The Callon Properties were not included in our consolidated results until the respective property transfer dates, which occurred during the fourth quarter of 2013. For the three months ended September 30, 2014, the Callon Properties accounted for $9.5 million of revenues, $2.2 million of direct operating expenses, $4.2 million of DD&A and $1.1 million of income taxes, resulting in $2.0 million of net income. For the nine months ended September 30, 2014, the Callon Properties accounted for $27.0 million of revenues, $4.2 million of direct operating expenses, $11.2 million of DD&A and $4.1 million of income taxes, resulting in $7.5 million of net income. The net income attributable to the Callon Properties does not reflect certain expenses, such as 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 Callon Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate. There were minimal expenses associated with acquisition activities and transition activities related to the acquisition of the Callon Properties for the three and nine months ended September 30, 2013.

Consistent with the computation of pro forma financial information presented in Item 8,*Financial Statements and Supplementary Data,* in the Annual Report on Form 10-K for the year end December 31, 2013, the unaudited pro forma financial information was computed as if the acquisition of the Callon Properties had been completed on January 1, 2012. 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, the Callon Properties' audited historical financial statement for 2012 and the Callon Properties' unaudited historical financial statements for interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Callon Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2012. Had we owned the Callon Properties during the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Callon; the realized sales prices for oil, NGLs and natural gas may have been different; and the costs of operating the Callon Properties may have been different.

The following table presents a summary of our pro forma financial information (in thousands, except earnings per share):

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Revenue	$ 255,195	$ 769,609
Net income	16,942	70,559
Basic and diluted earnings per common share	0.22	0.93

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

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

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Revenues (a)	$ 10,640	$ 30,449
Direct operating expenses (a)	1,619	5,711
DD&A (b)	4,405	12,349
Interest expense (c)	415	1,245
Capitalized interest (d)	(27)	(165)
Income taxes expense (e)	1,480	3,958

The sources of information and significant assumptions are described below:

(a) Revenues and direct operating expenses for the Callon Properties were derived from the historical financial records of Callon.

(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Callon 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.

(c) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $83.0 million, which equates to the cash component of the acquisition purchase price, and an interest rate of 2.0%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.

(d) 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.

(e) 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.

2013 Divestitures. On July 11, 2013, we sold our non-operated working interest in two offshore fields located in the Gulf of Mexico; the Green Canyon 60 field and the Green Canyon 19 field. The effective date was October 1, 2011 and we retained the deep rights in both fields. Due to the length of time from the effective date, we paid $4.3 million to sell the properties as revenues exceeded operating expenses and the purchase price for the period between the effective date and the close date. In connection with the sale, we reversed $15.6 million of our ARO.

On September 26, 2013, we sold our working interests in the West Delta area block 29 with an effective date of January 1, 2013. The property is located in the Gulf of Mexico. Including adjustments for the effective date, the net proceeds were $14.7 million, which includes a $1.7 million post-effective-date repayment that occurred during the nine months ended September 30, 2014. The transaction was structured as a like-kind exchange under the Internal Revenue Code ("IRC") Section 1031 and other applicable regulations, with funds held by a qualified intermediary until replacement purchases are made. Replacement purchases were made in 2013, which were within the replacement periods as defined under the IRC. In connection with this sale, we reversed $3.9 million of ARO.

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, 2013	$	354,422
Liabilities settled		(42,011)
Accretion of discount		15,312
Liabilities assumed through acquisition (1)		21,820
Liabilities incurred		943
Revisions of estimated liabilities (2)		53,516
Balance, September 30, 2014		404,002
Less current portion		115,722
Long-term	$	288,280

(1) Primarily attributable to the Woodside Properties acquisition and increased interest in Fairway.
(2) Revisions were primarily attributable to increases at various non-operated properties, revised regulations from the Bureau of Safety and Environmental Enforcement ("BSEE") and better defined scope of work on certain wells and platforms.

4. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. 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 and interest rate risk from floating interest rates on our revolving bank credit facility. 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.

In accordance with GAAP, we record each derivative contract on the balance sheet as an asset or a liability at its fair value. For additional information about fair value measurements, refer to Note 6. We have elected not to designate our commodity derivative contracts as hedging instruments; therefore, all changes in the fair value of derivative contracts are recognized currently in earnings. 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.

Commodity Derivatives. We have entered into commodity swap contracts to manage a portion of our exposure to commodity price risk from sales of oil through December 2014. While these contracts are intended to reduce the effects of price volatility, they may also limit future income from favorable price movements. During the nine months ended September 30, 2014 and during 2013, our derivative contracts consisted entirely of crude oil swap contracts. The crude oil swap contracts are comprised of a portion based on Brent crude oil prices, a portion based on West Texas Intermediate ("WTI") crude oil prices and a portion based on Light Louisiana Sweet ("LLS") crude oil prices. The Brent based swap contracts are priced off the Brent crude oil price quoted on the IntercontinentalExchange, known as ICE. The WTI based swap contracts are priced off the New York Mercantile Exchange, known as NYMEX. The LLS based swap contracts are priced from data provided by Argus, an independent media organization. Although our Gulf of Mexico crude oil is based off the WTI crude oil price plus or minus a differential, the realized prices received for our Gulf of Mexico crude oil, up until October 2013, have been closer to the Brent crude oil price because of competition with foreign supplied crude oil, which is based off the Brent crude oil price. Therefore, a portion of the oil swap contracts are priced off the Brent crude oil price to mitigate a portion of the price risk associated with our Gulf of Mexico crude oil production.

As of September 30, 2014, our open commodity derivative contracts were as follows:

		Swaps – Oil			
		Priced off Brent (ICE)		Priced off LLS (ARGUS)	
Termination Period		Notional Quantity (Bbls)	Weighted Average Contract Price	Notional Quantity (Bbls)	Weighted Average Contract Price
2014:	4th Quarter	156,400	$ 97.37	460,000	$ 98.12

Bbls = barrels

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

	September 30, 2014	December 31, 2013
Prepaid and other assets	$ 2,470	$ 141
Accrued liabilities	—	9,423

Changes in the fair value of our oil derivative contracts are recognized currently in earnings and were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Derivative (gain) loss:	$ (13,781)	$ 15,659	$ 6,790	$ 6,186

Cash payments on derivative 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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Cash payments on derivative settlements, net	$ 4,233	$ 4,545	$ 18,543	$ 6,855

Offsetting Commodity Derivatives. As of September 30, 2014 and December 31, 2013, all of our derivative agreements allowed for netting of derivative gains and losses upon settlement. In general, the terms of the agreements 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 currency. 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 instruments, we would be able to net payments and receipts per counterparty pursuant to the derivative agreements. Although our derivative agreements allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we account for our derivative contracts on a gross basis per contract as either an asset or liability.

The following table provides a reconciliation of the gross assets and liabilities reflected in the balance sheet and the potential effects of master netting agreements on the fair value of open derivative contracts (in thousands):

	September 30, 2014		December 31, 2013	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amounts presented in the balance sheet	$ 2,470	$ —	$ 141	$ 9,423
Amounts not offset in the balance sheet	—	—	(141)	(141)
Net Amounts	$ 2,470	$ —	$ —	$ 9,282

5. Long-Term Debt

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

	September 30, 2014	December 31, 2013
8.50% Senior Notes	$ 900,000	$ 900,000
Debt premiums, net of amortization	13,665	15,421
Revolving bank credit facility	347,000	290,000
Total long-term debt	1,260,665	1,205,421
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$ 1,260,665	$ 1,205,421

At September 30, 2014 and December 31, 2013, the balance outstanding of our senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the “8.50% Senior Notes”), was 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. We are subject to various financial and other covenants under the indenture governing the 8.50% Senior Notes and we were in compliance with those covenants as of September 30, 2014.

The Fifth Amended and Restated Credit Agreement (the “Credit Agreement”) governs our revolving bank credit facility and terminates 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 September 30, 2014 and December 31, 2013, we had $0.6 million and $0.4 million, respectively, of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 2.9% for the nine months ended September 30, 2014 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 September 30, 2014, our borrowing base was $750.0 million and our borrowing availability was $402.4 million. See Note 12 for information on our borrowing base, which was reaffirmed at $750.0 million effective October 22, 2014.

Under the Credit Agreement, we are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, each as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of September 30, 2014.

For information about fair value measurements for our 8.50% Senior Notes 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 value of our 8.50% Senior Notes is based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our 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 open derivative financial instruments, 8.50% Senior Notes and revolving bank credit facility (in thousands):

		September 30, 2014		December 31, 2013	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ 2,470	$ —	$ 141	$ 9,423
8.50% Senior Notes	Level 2	—	938,250	—	962,460
Revolving bank credit facility	Level 2	—	347,000	—	290,000

As described in Note 4, our open derivative financial instruments are reported in the balance sheet at fair value and changes in fair value are recognized currently in earnings. The 8.50% Senior Notes and revolving bank credit facility are reported in the balance sheet 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 the nine months ended September 30, 2014, and in 2013 and 2012, the Company granted restricted stock units ("RSUs") to certain of its employees. RSUs are a long-term compensation component of the Plan, which are granted to only certain employees, and are subject to adjustments at the end of the applicable performance period based on the 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 the nine months ended September 30, 2014, RSUs granted are subject to adjustments based on achievement of a combination of performance criteria, which is 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 revenue ("Adjusted EBITDA Margin") for 2014. Adjustments range from 0% to 100% dependent upon actual results compared against pre-defined performance levels.

During 2013, RSUs granted were subject to 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, was approximately at target for 2013 Adjusted EBITDA Margin and was below target for TSR ranking.

During 2012, RSUs granted were subject to a combination of performance criteria, which was comprised of: (i) earnings per share for 2012; and (ii) the Company's TSR ranking against peer companies' TSR for 2012, 2013 and January 1, 2014 to October 31, 2014. Pursuant to the Plan, discretionary authority was exercised for certain non-executive employees, which reduced the forfeitures that would have occurred through application of the pre-defined performance measurement.

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 2012 will vest in December 2014 to eligible employees.

The 2014 annual incentive plan award for the Chief Executive Officer ("CEO") will be settled in shares of common stock based on a price of $14.66 per share, subject to pre-defined performance measures and approval of the Compensation Committee. As the number of shares cannot be determined and a grant has not yet been made, the CEO's 2014 award is accounted for as a liability award and adjusted to fair value using the Company's closing price at the end of each reporting period. The compensation related to the 2013 annual incentive plan for the CEO was determined based on pre-defined company and individual performance measures pursuant to the terms of his award and was settled in shares of common stock in March 2014. The performance measures for the CEO's award were the same as the performance measures established for the other eligible Company employees for 2014 and 2013, respectively.

Under the Director Compensation Plan, shares of restricted stock ("Restricted Shares") were granted to the Company's non-employee directors during 2014 and prior years. The Restricted Shares are subject to service conditions and vesting occurs at the end of specified service periods.

At September 30, 2014, there were 5,032,939 shares of common stock available for issuance in satisfaction of awards under the Plan and 500,564 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 will reduce the shares available in the Plan only when RSUs are settled in shares of common stock. Although the Company has the option to settle RSUs in stock or cash at vesting, only common stock has been used to settle vested RSUs to date.

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

Awards Based on Restricted Stock to Non-Employee Directors. As of September 30, 2014, 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 2014 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, 2013	43,840	$ 15.96
Granted	18,815	18.60
Vested	(19,445)	18.00
Nonvested, September 30, 2014	43,210	$ 16.20

Subject to the satisfaction of service conditions, the outstanding Restricted Shares issued to the non-employee directors as of September 30, 2014 are expected to vest as follows:

	Restricted Shares
2015	21,520
2016	15,420
2017	6,270
Total	43,210

The grant date fair value of Restricted Shares granted during the nine months ended September 30, 2014 and 2013 was $0.3 million and $0.3 million, respectively. The fair value of Restricted Shares that vested during the nine months ended September 30, 2014 and 2013 was $0.3 million and $0.4 million, respectively.

Awards Based on Restricted Stock Units. As of September 30, 2014, the Company had outstanding RSUs issued to certain employees. As described above, the RSUs granted during the nine months ended September 30, 2014 are subject to pre-defined performance measures which cannot be determined at this time; therefore, no portion has been determined to be eligible for vesting as of September 30, 2014. A portion of the RSUs granted during 2013 and 2012 remains subject to certain pre-defined performance measures of TSR for the defined periods in 2014 and 2015; therefore, the number of RSUs may be adjusted upon determination of the respective performance. These RSU adjustments related to TSR performance will not affect unrecognized expense, as the fair value of the portion related to market-based awards was established at the date of grant (described below) and actual performance does not affect expense recognition for this portion. The portion of RSUs subject to performance measurement and adjustment ranges are disclosed in the second table below.

The fair value for the RSUs granted during the nine months ended September 30, 2014 was determined using the Company's closing price on the grant date. The fair value for the 2013 RSUs was determined separately for the component related to the Company specific performance measures (Adjusted EBITDA and Adjusted EBITDA Margin) and the component related to TSR targets. The fair value of the 2013 RSUs component related to the Company specific performance measures was determined using the Company's closing price on the grant date. 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 London Interbank Offered Rate ("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 (84%) to 95%. The expected volatilities, expected dividends and correlation factors were developed using historical data.

A methodology similar to that employed for the 2013 RSUs was used to determine the fair value for the 2012 RSUs. The inputs used in the probabilistic model for the Company and the peer companies were: average closing stock prices during January 2012; risk-free interest rates using the LIBOR ranging from 0.15% to 0.72% over the service period; expected volatilities ranging from 33% to 74%; expected dividend yields ranging from 0.0% to 2.5%; and correlation factors ranging from (67%) to 94%. The expected volatilities, expected dividends and correlation factors were developed using historical data.

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 2014 related to RSUs is as follows:

	Restricted Stock Units	
	Units	**Weighted Average Grant Date Fair Value Per Unit**
Nonvested, December 31, 2013	1,331,753	$ 14.96
Granted	1,190,920	16.83
Vested	(4,662)	16.26
Forfeited	(36,422)	15.57
Nonvested, September 30, 2014	2,481,589	$ 15.85

All of the outstanding RSUs are subject to the satisfaction of service conditions and a portion of the outstanding RSUs are also subject to pre-defined performance measurements. The RSUs outstanding as of September 30, 2014 potentially eligible to vest are listed in the table below:

	Restricted Stock Units
2014 - subject to service requirements	350,031
2014 - subject to service and other requirements (1)	66,688
2015 - subject to service requirements	705,176
2015 - subject to service and other requirements (2)	180,211
2016 - subject to service requirements	3,400
2016 - subject to service and other requirements (3)	1,176,083
Total	2,481,589

(1) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 150% of amounts granted.
(2) 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.
(3) In addition to service requirements, these RSUs are also subject to Company specific performance requirements not yet measureable, with awards ranging from 0% to 100% of amounts granted.

The grant date fair value of RSUs granted during the nine months ended September 30, 2014 and 2013 was $20.0 million and $12.8 million, respectively. The fair value of RSUs that vested during the nine months ended September 30, 2014 was $0.1 million and resulted from a retirement. During the nine months ended September 30, 2013, there was no vesting of RSUs.

Awards Based on Common Stock. A grant and issuance of 42,547 shares of common stock was made in March 2014 to the CEO pursuant to the terms of his 2013 annual incentive compensation award. The number of shares was determined after deductions for withholding and payroll taxes and the shares were valued at the Company's closing price as of the date of grant.

Share-Based Compensation. A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Share-based compensation expense from:				
Restricted stock	$ 93	$ 99	$ 276	$ 297
Restricted stock units	3,658	3,408	9,819	8,160
Common shares	3	—	1,303	—
Total	$ 3,754	$ 3,507	$ 11,398	$ 8,457
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$ 1,314	$ 1,227	$ 3,989	$ 2,960

Unrecognized Share-Based Compensation. As of September 30, 2014, unrecognized share-based compensation expense related to our awards of Restricted Shares, RSUs and common stock was $0.6 million, $21.7 million and $0.2 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2017 for Restricted Shares, November 2016 for RSUs and February 2015 for awards based on common shares.

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 are paid in shares of common stock as described above.) These awards are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Share-based compensation included in:				
General and administrative (1)	$ 3,754	$ 3,507	$ 11,398	$ 8,457
Cash-based incentive compensation included in:				
Lease operating expense	586	724	2,363	2,864
General and administrative (1)	2,724	2,191	6,038	7,745
Total charged to operating income	$ 7,064	$ 6,422	$ 19,799	$ 19,066

(1) Reclassified $0.7 million from cash-based incentive compensation expense to share-based compensation expense in the nine months ended September 30, 2014 related to the CEO's 2013 award.

8. Income Taxes

Income tax expense of $0.9 million and $12.8 million was recorded during the three and nine months ended September 30, 2014, respectively. Our effective tax rate for the three months ended September 30, 2014 was not meaningful due to adjustments for a revised estimated effective tax rate computed on a year-to-date basis. Our effective tax rate for the nine months ended September 30, 2014 was 37.1%. The rate for the nine months ended September 30, 2014 differed from the federal statutory rate of 35.0% primarily as a result of state income taxes and other permanent items. Income tax expense of $8.0 million and $35.4 million was recorded during the three and nine months ended September 30, 2013, respectively. The effective tax rate for the three and nine months ended September 30, 2013 was 36.1% and 35.9%, respectively, and differed from the federal statutory rate primarily as a result of state income taxes.

During the nine months ended September 30, 2014, we received $3.0 million of refunds. During 2013, we received refunds of $59.1 million, of which $9.5 million of these refunds have been accounted for as unrecognized tax benefits. We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the three and nine months ended September 30, 2014 and 2013, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit. As of September 30, 2014 and December 31, 2013, we had a valuation allowance related to state net operating losses. 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. The tax years from 2010 through 2013 remain open to examination by the tax jurisdictions to which we are subject.

9. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$ 684	$ 14,194	$ 21,710	$ 63,208
Less portion allocated to nonvested shares	70	159	208	713
Net income allocated to common shares	$ 614	$ 14,035	$ 21,502	$ 62,495
Weighted average common shares outstanding	75,613	75,233	75,592	75,221
Basic and diluted earnings per common share	$ 0.01	$ 0.19	$ 0.28	$ 0.83
Shares excluded due to being anti-dilutive (weighted-average)	—	851	—	860

10. Dividends

During the nine months ended September 30, 2014 and 2013, we paid regular cash dividends per common share of $0.30 and $0.26, respectively. On November 5, 2014, our board of directors declared a cash dividend of $0.10 per common share, payable on December 3, 2014 to shareholders of record on November 18, 2014.

11. Contingencies

Notice of Lifting of Suspension and Debarment. On August 5, 2014, the Parent Company received notice that the U.S. Environmental Protection Agency (the "EPA") lifted the suspension and proposed debarment, and removed the statutory disqualification, previously imposed by the EPA (as discussed below). This action is subject to the condition that the Parent Company continue to comply with the conditions of its existing probation resulting from environmental violations relating to our Ewing Banks 910 platform in the Gulf of Mexico, as described in Item 8, *Financial Statements and Supplementary Data*, in our Annual Report on Form 10-K for the year end December 31, 2013. The EPA's action allows full participation by the Parent Company in future federal contracts, including future federal oil and gas leases, assistance activities and federal oil and gas leasing activities.

Previously in November 2013, the Parent Company, received a Notice of Suspension and Proposed Debarment and a Notice of Clean Water Act Listing (the "Notices") from the EPA. The Notices were directed to only the Parent Company and did not name or apply to our 100%-owned subsidiaries. The first Notice suspended the Parent Company and proposed a three year debarment from participation in future federal contracts, including future federal oil and gas leases, and assistance activities and would have rendered the Parent Company ineligible to receive any federal contracts or approved subcontracts or to act as an agent or representative on behalf of another in such transaction, or receive certain federal benefits. The second Notice provided a narrower prohibition on federal contracts or benefits for the Parent Company. The Notices stemmed from the Parent Company's previously disclosed plea agreement and corporate conviction on two criminal counts as described in Item 8, *Financial Statements and Supplementary Data*, in our Annual Report on Form 10-K for the year end December 31, 2013. The Notices prevented the Parent Company from obtaining federal oil and gas leases, whether at a future lease sale or an existing lease by assignment. The Notices did not affect current or future drilling or production operations of the existing lease ownership of the Parent Company.

Waiver Concerning Certain Supplement Bonding Requirements from the Bureau of Ocean Energy Management ("BOEM"). On May 16, 2014, the Parent Company was informed by the BOEM that under applicable federal regulations it now qualifies for a waiver of certain supplemental bonding requirements for potential offshore decommissioning liabilities (including plugging and abandonment), effectively reversing the actions of the BOEM discussed below. The waiver of certain supplemental bonding requirements pertains to the Parent Company only as our 100%-owned subsidiary, Energy VI, is not exempt from supplemental bonding under BOEM's procedures and, therefore, such 100%-owned subsidiary provides supplemental bonding for its plugging and abandonment liabilities as required by BOEM's procedures.

Previously in November and December 2013, the Parent Company received letters from the BOEM claiming that it no longer qualified for a waiver of certain supplemental bonding requirements for potential offshore decommissioning liabilities (including plugging and abandonment). The letters notified the Parent Company that it must provide supplemental bonding on certain of its offshore leases, rights of way and rights of use and easement in the Gulf of Mexico. In response to the letters, the Company filed a petition, provided additional information to the BOEM and had discussions with the BOEM staff to bring resolution to the matter.

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 and extreme 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 ONRR's allegations contained in the notice. The U.S. Department of Interior granted a stay in the matter due to the ONRR counsel's temporary leave and we have requested a lifting of the stay as ONRR's counsel has returned to work. We intend to contest the fine to the fullest extent possible. The ultimate resolution may result in a waiver of the fine, a reduction of the fine, or payment of the full amount plus interest covering several years. As no amount has been determined as more likely than any other within the range of possible resolutions, no amount has been accrued as of September 30, 2014 per authoritative guidance. However, we cannot state with certainty that our estimate of the exposure is accurate concerning this matter.

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 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., has paid their portion of the settlement (approximately $5 million), including interest, although the commencement date of the interest calculation is under discussion. The other four 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. The revised estimate of potential reimbursement is approximately $35 million, plus interest at 18%, 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 and have not yet filed our statement of reasons. We were granted an extension to November 24, 2014 to file our statement of reasons in conjunction with the BLA appeal.

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. 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. During the three and nine months ended September 30, 2014, $0.0 million and $0.3 million ofexpenses, respectively, were recognized related to claims, complaints and fines. During the three and nine months ended September 30, 2013, expenses recognized related to claims, complaints and fines were $0.3 million. As of September 30, 2014 and December 31, 2013, we have recorded $0.5 million and $0.2 million, respectively, which are included in *Accrued liabilities* on the Condensed Consolidated Balance Sheets, for the loss contingencies matters in the normal course of business.

12. Subsequent Events

Availability under our revolving bank credit facility is subject to semi-annual redetermination. On October 22, 2014, we received the redetermination notice from our lenders that the borrowing base under our revolving bank credit facility remained at $750.0 million.

13. Supplemental Guarantor Information

Our payment obligations under the 8.50% Senior Notes and the Credit Agreement (see Note 5) are fully and unconditionally guaranteed by certain of our 100%-owned subsidiaries, including W & T Energy VI, LLC 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 (as such term is defined in the indenture governing the 8.50% Senior Notes) of the Company, if the sale or other disposition does not violate the "Asset Sales" provisions of the indenture;

(2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the "Asset 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 the indenture;

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

(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 of the 8.50% Senior Notes as described in the indenture, 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, including related ARO and deferred income tax liabilities, were made from the Parent Company to the Guarantor Subsidiaries to assist the Parent Company to continue to qualify for a waiver of certain supplemental bonding requirements from the BOEM. See Note 11 for additional information. 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. The condensed consolidating financial information for current and prior periods was adjusted as if all transfers occurred at the beginning of the period presented. Additionally, certain adjustments were made to re-designate certain items as intercompany or contributed capital from the Parent Company to the Guarantor Subsidiaries, which had no effect on either entity's net property and equipment or total liabilities. None of the above adjustments had any effect on the consolidated results for the current or prior periods presented.

Condensed Consolidating Balance Sheet as of September 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 17,220	$ —	$ —	$ 17,220
Receivables:				
Oil and natural gas sales	52,332	45,356	—	97,688
Joint interest and other	32,785	—	—	32,785
Income taxes	136,389	—	(136,269)	120
Total receivables	221,506	45,356	(136,269)	130,593
Prepaid expenses and other assets	29,364	3,191	—	32,555
Total current assets	268,090	48,547	(136,269)	180,368
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,970,031	1,895,671	—	7,865,702
Furniture, fixtures and other	22,128	—	—	22,128
Total property and equipment	5,992,159	1,895,671	—	7,887,830
Less accumulated depreciation, depletion and amortization	4,366,703	1,082,842	—	5,449,545
Net property and equipment	1,625,456	812,829	—	2,438,285
Restricted deposits for asset retirement obligations	15,382	—	—	15,382
Other assets	979,751	439,882	(1,401,644)	17,989
Total assets	$ 2,888,679	$ 1,301,258	$ (1,537,913)	$ 2,652,024
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 153,928	$ 5,693	$ —	$ 159,621
Undistributed oil and natural gas proceeds	37,501	320	—	37,821
Asset retirement obligations	109,223	6,499	—	115,722
Accrued liabilities	39,313	135,986	(136,269)	39,030
Total current liabilities	339,965	148,498	(136,269)	352,194
Long-term debt, less current maturities	1,260,665	—	—	1,260,665
Asset retirement obligations, less current portion	175,135	113,145	—	288,280
Deferred income taxes	94,042	93,015	—	187,057
Other liabilities	468,678	—	(455,044)	13,634
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	414,430	699,815	(699,815)	414,430
Retained earnings	159,930	246,785	(246,785)	159,930
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	550,194	946,600	(946,600)	550,194
Total liabilities and shareholders' equity	$ 2,888,679	$ 1,301,258	$ (1,537,913)	$ 2,652,024

Condensed Consolidating Balance Sheet as of December 31, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 15,800	$ —	$ —	$ 15,800
Receivables:				
Oil and natural gas sales	61,373	35,379	—	96,752
Joint interest and other	27,984	—	—	27,984
Income taxes	95,611	—	(92,491)	3,120
Total receivables	184,968	35,379	(92,491)	127,856
Prepaid expenses and other assets	23,674	6,272	—	29,946
Total current assets	224,442	41,651	(92,491)	173,602
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,667,389	1,671,708	—	7,339,097
Furniture, fixtures and other	21,431	—	—	21,431
Total property and equipment	5,688,820	1,671,708	—	7,360,528
Less accumulated depreciation, depletion and amortization	4,166,359	918,345	—	5,084,704
Net property and equipment	1,522,461	753,363	—	2,275,824
Restricted deposits for asset retirement obligations	37,421	—	—	37,421
Other assets	951,203	479,820	(1,410,568)	20,455
Total assets	$ 2,735,527	$ 1,274,834	$ (1,503,059)	$ 2,507,302
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 144,492	$ 720	$ —	$ 145,212
Undistributed oil and natural gas proceeds	41,735	372	—	42,107
Asset retirement obligations	65,329	12,456	—	77,785
Accrued liabilities	28,000	92,491	(92,491)	28,000
Total current liabilities	279,556	106,039	(92,491)	293,104
Long-term debt, less current maturities	1,205,421	—	—	1,205,421
Asset retirement obligations, less current portion	189,507	87,130	—	276,637
Deferred income taxes	79,424	98,718	—	178,142
Other liabilities	441,009	—	(427,621)	13,388
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	403,564	784,104	(784,104)	403,564
Retained earnings	161,212	198,843	(198,843)	161,212
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	540,610	982,947	(982,947)	540,610
Total liabilities and shareholders' equity	$ 2,735,527	$ 1,274,834	$ (1,503,059)	$ 2,507,302

Condensed Consolidating Statement of Income for the Three Months Ended September 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 155,109	$ 79,412	$ —	$ 234,521
Operating costs and expenses:				
Lease operating expenses	46,698	25,034	—	71,732
Production taxes	1,794	—	—	1,794
Gathering and transportation	2,831	1,284	—	4,115
Depreciation, depletion, amortization and accretion	74,512	54,159	—	128,671
General and administrative expenses	12,083	8,924	—	21,007
Derivative (gain)	(13,781)	—	—	(13,781)
Total costs and expenses	124,137	89,401	—	213,538
Operating income (loss)	30,972	(9,989)	—	20,983
Earnings of affiliates	(9,652)	—	9,652	—
Interest expense:				
Incurred	20,932	851	—	21,783
Capitalized	(1,340)	(851)	—	(2,191)
Other income	197	—	—	197
Income (loss) before income tax expense	1,925	(9,989)	9,652	1,588
Income tax expense (benefit)	1,241	(337)	—	904
Net income (loss)	$ 684	$ (9,652)	$ 9,652	$ 684

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 461,167	$ 290,864	$ —	$ 752,031
Operating costs and expenses:				
Lease operating expenses	126,423	62,693	—	189,116
Production taxes	5,628	—	—	5,628
Gathering and transportation	8,387	5,009	—	13,396
Depreciation, depletion, amortization and accretion	208,271	171,942	—	380,213
General and administrative expenses	34,165	30,112	—	64,277
Derivative loss	6,790	—	—	6,790
Total costs and expenses	389,664	269,756	—	659,420
Operating income	71,503	21,108	—	92,611
Earnings of affiliates	10,738	—	(10,738)	—
Interest expense:				
Incurred	63,078	1,625	—	64,703
Capitalized	(4,797)	(1,625)	—	(6,422)
Other income	205	—	—	205
Income before income tax expense	24,165	21,108	(10,738)	34,535
Income tax expense	2,455	10,370	—	12,825
Net income	$ 21,710	$ 10,738	$ (10,738)	$ 21,710

Condensed Consolidating Statement of Income for the Three Months Ended September 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 161,927	$ 82,628	$ —	$ 244,555
Operating costs and expenses:				
Lease operating expenses	51,028	16,318	—	67,346
Production taxes	1,807	—	—	1,807
Gathering and transportation	1,479	2,132	—	3,611
Depreciation, depletion, amortization and accretion	58,014	46,129	—	104,143
General and administrative expenses	11,337	8,687	—	20,024
Derivative loss	15,659	—	—	15,659
Total costs and expenses	139,324	73,266	—	212,590
Operating income	22,603	9,362	—	31,965
Earnings of affiliates	6,171	—	(6,171)	—
Interest expense:				
Incurred	20,611	762	—	21,373
Capitalized	(1,811)	(762)	—	(2,573)
Other income	9,062	—	—	9,062
Income before income tax expense	19,036	9,362	(6,171)	22,227
Income tax expense	4,842	3,191	—	8,033
Net income	$ 14,194	$ 6,171	$ (6,171)	$ 14,194

Condensed Consolidating Statement of Income for the Nine Months Ended September 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 479,537	$ 259,623	$ —	$ 739,160
Operating costs and expenses:				
Lease operating expenses	145,703	49,232	—	194,935
Production taxes	5,375	—	—	5,375
Gathering and transportation	6,590	6,073	—	12,663
Depreciation, depletion, amortization and accretion	176,922	135,989	—	312,911
General and administrative expenses	35,222	25,757	—	60,979
Derivative loss	6,186	—	—	6,186
Total costs and expenses	375,998	217,051	—	593,049
Operating income	103,539	42,572	—	146,111
Earnings of affiliates	27,812	—	(27,812)	—
Interest expense:				
Incurred	61,932	2,225	—	64,157
Capitalized	(5,312)	(2,225)	—	(7,537)
Other income	9,075	—	—	9,075
Income before income tax expense	83,806	42,572	(27,812)	98,566
Income tax expense	20,598	14,760	—	35,358
Net income	$ 63,208	$ 27,812	$ (27,812)	$ 63,208

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 21,710	$ 10,738	$ (10,738)	$ 21,710
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	208,271	171,942	—	380,213
Amortization of debt issuance costs and premium	537	—	—	537
Share-based compensation	11,398	—	—	11,398
Derivative loss	6,790	—	—	6,790
Cash payments on derivative settlements	(18,543)	—	—	(18,543)
Deferred income taxes	17,621	(4,796)	—	12,825
Earnings of affiliates	(10,738)	—	10,738	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	9,041	(9,977)	—	(936)
Joint interest and other receivables	1,890	—	—	1,890
Income taxes	(12,283)	15,167	—	2,884
Prepaid expenses and other assets	35,223	(41,419)	27,424	21,228
Asset retirement obligations settlements	(28,492)	(13,519)	—	(42,011)
Accounts payable, accrued liabilities and other	49,463	4,921	(27,424)	26,960
Net cash provided by operating activities	291,888	133,057	—	424,945
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(18,152)	(53,363)	—	(71,515)
Investment in oil and natural gas properties and equipment	(245,561)	(138,392)	—	(383,953)
Net proceeds from sales of properties and equipment	—	—	—	—
Change in restricted cash	—	—	—	—
Investment in subsidiary	(58,698)	—	58,698	—
Purchases of furniture, fixtures and other	(2,181)	—	—	(2,181)
Net cash used in investing activities	(324,592)	(191,755)	58,698	(457,649)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	378,000	—	—	378,000
Repayments of long-term debt – revolving bank credit facility	(321,000)	—	—	(321,000)
Dividends to shareholders	(22,695)	—	—	(22,695)
Other	(181)	—	—	(181)
Investment from parent	—	58,698	(58,698)	—
Net cash provided in financing activities	34,124	58,698	(58,698)	34,124
Increase in cash and cash equivalents	1,420	—	—	1,420
Cash and cash equivalents, beginning of period	15,800	—	—	15,800
Cash and cash equivalents, end of period	$ 17,220	$ —	$ —	$ 17,220

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 63,208	$ 27,812	$ (27,812)	$ 63,208
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	176,922	135,989	—	312,911
Amortization of debt issuance costs and premium	1,366	—	—	1,366
Share-based compensation	8,457	—	—	8,457
Derivative gain	6,186	—	—	6,186
Cash payments on derivative settlements	(6,855)	—	—	(6,855)
Deferred income taxes	13,451	18,130	—	31,581
Earnings of affiliates	(27,812)	—	27,812	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	13,260	(749)	—	12,511
Joint interest and other receivables	30,064	—	—	30,064
Income taxes	56,802	(3,369)	—	53,433
Prepaid expenses and other assets	(6,823)	(52,400)	48,408	(10,815)
Asset retirement obligations	(48,098)	(11,090)	—	(59,188)
Accounts payable, accrued liabilities and other	58,051	23,331	(48,408)	32,974
Net cash provided by operating activities	338,179	137,654	—	475,833
Investing activities:				
Investment in oil and natural gas properties and equipment	(285,438)	(137,654)	—	(423,092)
Net proceeds from sales of properties and equipment	21,011	—	—	21,011
Change in restricted cash	(16,459)	—	—	(16,459)
Purchases of furniture, fixtures and other	(1,327)	—	—	(1,327)
Net cash used in investing activities	(282,213)	(137,654)	—	(419,867)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	335,000	—	—	335,000
Repayments of long-term debt – revolving bank credit facility	(368,000)	—	—	(368,000)
Dividends to shareholders	(19,570)	—	—	(19,570)
Other	(414)	—	—	(414)
Net cash used in financing activities	(52,984)	—	—	(52,984)
Increase in cash and cash equivalents	2,982	—	—	2,982
Cash and cash equivalents, beginning of period	12,245	—	—	12,245
Cash and cash equivalents, end of period	$ 15,227	$ —	$ —	$ 15,227

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, 2013 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 approximately 66 producing offshore fields in federal and state waters (62 producing and four fields capable of producing). We currently have under lease approximately 1.2 million gross acres, including approximately 0.6 million gross acres on the Gulf of Mexico Shelf, approximately 0.6 million gross acres in the deepwater and approximately 50,000 gross acres onshore, substantially all of which is in the Permian Basin of West Texas. A substantial majority of our daily production is derived from wells we operate offshore. Our interests in fields, leases, structures and equipment are primarily owned by the Parent Company, W&T Offshore, Inc. and our 100%-owned subsidiary, W & T Energy VI, LLC. In managing our business, we are concerned primarily with maximizing return on shareholders' equity. To accomplish this primary goal, we focus on profitably increasing production and finding oil and gas reserves at a favorable cost. We strive to grow our reserves and production through both acquisitions and our drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to continue to add reserves post-acquisition.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for the nine months ended September 30, 2014 were comprised of 41.0% oil and condensate, 11.8% NGLs and 47.2% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel oil equivalent ("Boe") for oil, NGLs and natural gas has differed significantly from time to time. In the nine months ended September 30, 2014, revenues from the sale of oil and NGLs made up 77.2% of our total revenues compared to 81.3% for the same period of 2013. For the nine months ended September 30, 2014, our combined total production and total revenues were 1.7% higher than the same period in 2013 due to higher oil production and higher natural gas prices, partially offset by lower oil prices. See *Results of Operations – Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013* and *Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013* 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 and the incremental impact was minimal. The results for the three and nine months ended September 30, 2013 do not include the increased ownership interest in Fairway as this period precedes the acquisition date. See Part I, Item 1*, Financial Statements - Note 2 - Acquisitions and Divestitures,* 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. The results for the three and nine months ended September 30, 2013 do not include the Woodside Properties' operations as this period precedes the acquisition date. See Part I, Item 1*, Financial Statements - Note 2 - Acquisitions and Divestitures,* of this Form 10-Q for additional information

In November and December 2013, we acquired certain oil and gas leasehold interests in the Gulf of Mexico from Callon. The Callon Properties consist of a 15% working interest in the Medusa field (deepwater Mississippi Canyon blocks 582 and 583), an interest in associated production facilities and various interests in other non-operated fields. The operating results of the Callon Properties are included in our results for the three and nine months ended September 30, 2014. The results for the three and nine months ended September 30, 2013 do not include the Callon Properties' operations as this period precedes the acquisition date. See Part I, Item 1, *Financial Statements - Note 2 - Acquisitions and Divestitures*, 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. For the first nine months of 2014, WTI and Brent crude oil prices averaged above $100 per barrel. Crude oil prices have fallen dramatically recently (from a peak of $107 per barrel for WTI in June 2014 to a recent low of $79 per barrel in October 2014) as a result of a number of macro issues, including weaker anticipated global demand (both China and Europe), growing crude supplies, especially with shut-in production returning to the market (primarily from Libya), and the strengthening U.S. dollar. A summary of those events follow:

Reduced prospects for the Chinese economy and deteriorating economic conditions across Europe, especially Germany, have made a significant impact on views about future oil demand which has led to falling anticipated demand and price weakness. U.S. Energy Information Administration ("EIA") forecasts global incremental demand growing around 700,000 barrels per day in 2014 compared to previous forecasts of 1.2 million barrels per day. Forecasted global GDP growth of 3.2% for 2014 could have implied petroleum product demand growth of around 1.2 million barrels per day. GDP growth is now forecast to be at 2.8%, consistent with the 700,000 barrels per day demand growth. At the same time as demand weakened, production from Libya has risen from 200,000 barrels per day to over 900,000 barrels per day. Further, OPEC members have taken no actions to reduce supply and Saudi Arabia is working to maintain market share in Asia. U.S. oil production continues to increase and is displacing crude imports from both Nigeria and Algeria and contributing to the growing oversupply of crude oil on the market. 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.

At this time, we have not adjusted our current operations or drilling plans. We have been closely monitoring current and forecasted prices to assess if changes are needed to our plans. No conclusions have been reached thus far as the recent price decline has been steep and unexpected.

The increase in United States crude oil production has been a major contributor to the increase in world-wide production during 2014. U.S. crude oil production for September 2014 was at the highest level since July 1986, as reported by the EIA. EIA estimates petroleum and other liquids production for 2014 will average 13.8 million barrels per day compared to 12.3 million barrels per day for 2013. EIA estimates U.S. petroleum and other liquids production for 2015 to increase further to average 15.1 million barrels per day. Total world production of petroleum and other liquids for 2013, 2014 and 2015 is estimated to average 90.2, 91.8 and 92.7 million barrels per day, respectively. World-wide inventories are expected to build by 0.3 million barrels per day in 2014, which was approximately the same amounts of inventory drawdowns occurring during 2013. These EIA forecasts were made prior to the recent drop in crude oil prices in October 2014, which could cause significant changes to their supply and demand forecasts.

In addition to U.S. crude oil production, another factor affecting the price of domestic crude oil is the ability to get production to market. Over the past few years, the infrastructure to transport crude oil within the United States has seen a major change. A number of pipelines have been built and completed, reversed flowed, or expanded to move crude oil from Cushing, Oklahoma (a major crude oil storage hub) primarily to the U.S. Gulf Coast but also to the Midwest as well. Transportation capacity has also been added in major producing regions, like the Permian Basin, to move crude oil to the U.S. Gulf Coast rather than to Cushing. Both of these events have helped relieve the excess crude oil that built up in Cushing (inventories have decreased from a high of over 50 million barrels to a low of 18 million barrels over the last year), which in turn allowed WTI pricing to increase relative to Brent. Up to the fourth quarter of 2013, WTI traded at a discount to Brent, while our Gulf Coast crude oil production traded at a premium to WTI. Beginning in the fourth quarter of 2013 and continuing during the nine months ended September 30, 2014, the premiums for the Gulf of Mexico crude oil have declined as the crude being moved to the U.S. Gulf Coast increased and imports continued. The structural changes that have occurred as a result of new pipeline and rail infrastructure are expected to impact U.S. Gulf Coast crude oil pricing going forward. During the second and third quarter of 2014, premiums for LLS and Heavy Louisiana Sweet (“HLS”) relative to WTI reverted to more historical levels and some Gulf Coast crudes traded at a discount to WTI as a result of the pricing competition occurring on the Gulf Coast. Rail receiving capacity has also been expanding rapidly on the East Coast, and to some extent on the U.S. Gulf Coast, with more capacity being announced. The average spread between Brent and WTI was 35% lower during the nine months ended September 30, 2014 compared to the same period in 2013 as a result of the increased domestic production and structural changes outlined above. The Brent-WTI spread has declined during 2014, as the spread for September 2014 was 40% lower than the nine month average for 2014.

During the nine months ended September 30, 2014, our average realized oil sales price was fairly strong by historical standards but was 7.0% lower than that realized in the same period of 2013. Our realized sales price was lower while the benchmark crude WTI for this time frame was higher due to the reduction in our offshore crude oil premiums as discussed above. As reported by the EIA, WTI prices averaged $100.01 per barrel for the first nine months of 2014, up from $98.15 per barrel for the comparable period. Brent prices decreased to $106.63 per barrel for the first nine months of 2014 from $108.29 per barrel for the comparable period of 2013. 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. Over 85% of our oil is produced from offshore in the Gulf of Mexico and is characterized as LLS, HLS, Poseidon and others. Prior to 2014, we had been realizing strong premiums on our Gulf Coast crudes. These premiums decreased significantly beginning in the fourth quarter of 2013 and continued at lower levels through the third quarter of 2014. For example, the monthly average premiums to WTI for LLS, HLS and Poseidon for the nine months ended September 30, 2014 were $4.12, $4.05 and a negative $1.01 per barrel, respectively, compared to $13.88, $13.81 and $8.54 per barrel, respectively, for the comparable 2013 period. Permian crudes also have been trading at a discount to WTI and likely will continue to do so until the pipeline and rail capacity that has been announced is constructed and put in to service. Our oil production in West Texas incurs discounts for transportation costs incurred by the purchaser, with larger discounts applied where the oil is trucked due to lack of pipeline access.

Our average realized NGLs sales prices increased 11.9% during the nine months ended September 30, 2014 versus the comparable 2013 period. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the nine months ended September 30, 2014, average prices for domestic ethane increased 11% and average domestic propane prices increased 28% from the comparable 2013 period. Average price changes for other domestic NGLs ranged from a decrease of 9% to an increase of 1%. Colder weather was a major factor for the increase of the price of propane during the winter months of 2014; however, propane prices were below prior year levels for the months of August and September 2014. Other market factors and weather influence the price of ethane, as it is not used directly as a heating fuel. However, cold weather drove up the price of natural gas, helping to increase the price of ethane, which is extracted from natural gas. Once the cold weather passed, ethane prices declined to pre-winter pricing and prices for the third quarter of 2014 were below the comparable 2013 period. As long as the price ratio of crude oil to natural gas remains wide (as measured on a six to one energy equivalency), the production of NGLs may continue to be high relative to historical norms and would, in turn, suggest downward price pressure on the price of ethane. Many natural gas processing facilities are re-injecting ethane back into the natural gas stream after processing due to insufficient ethane demand, which negatively impacts production and natural gas prices.

Prices for natural gas in the U.S. improved during the nine months ended September 30, 2014 versus the comparable 2013 period largely due to above-average storage withdrawals in response to the colder winter weather in 2014 and higher industrial demand. The amount of heating degree days for the winter of 2014 was 13% higher than that of 2013, which was a primary causal factor for the increased demand. 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. During the nine months ended September 30, 2014, the average realized sales price for our natural gas production increased 21.4% to $4.54 per Mcf from the comparable 2013 period. Natural gas prices at Henry Hub (the primary U.S. price benchmark) using the unweighted average daily posted spot price, increased 24.1% from the comparable period. Average realized natural gas prices decreased slightly in the third quarter of 2014 compared to the second quarter of 2014, but were higher than the third quarter of 2013.

Although the price of natural gas has increased significantly on a percentage basis, it 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 continuing to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas continuing to be produced as a by-product in conjunction with the high level of oil drilling (as evidenced by the year over year increase in natural gas production despite the decline in the number of rigs drilling for natural gas as explained below), (iii) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling and production techniques and (iv) re-injecting ethane into the natural gas stream as indicated above, which increases the natural gas supply.

Per EIA, natural gas working inventories at the end of the September 2014 were estimated at 3.2 trillion cubic feet, which is 11% below the comparable 2013 period. EIA estimates the Henry Hub natural gas spot price was $4.73 per Mcf in the nine months ended September 30, 2014 and forecasts $4.58 per Mcf for all of 2014 and $3.95 per Mcf in 2015. Even with the colder winter, EIA projects U.S. supply to be higher than consumption for both 2014 and 2015.

According to Baker Hughes, the U.S. natural gas rig count was 439 at the beginning of 2013. The natural gas rig count decreased during 2013 to 372 rigs at the end of 2013 and decreased further to 330 at the end of September 2014. The natural gas rig count was at a 21 year low during 2014. Despite the decline in rigs drilling specifically for natural gas, the U.S. has experienced a year over year increase in natural gas production due to the many factors previously enumerated. Oil wells have increased natural gas production as a by-product, with the number of rigs searching for oil increasing from 1,318 at the beginning of 2013 to 1,378 at the end of 2013, and further increasing to 1,591 as of the end of September 2014. In the Gulf of Mexico, there were 48 rigs (29 oil, 19 natural gas) at the beginning of 2013, 59 rigs (39 oil, 20 natural gas) at the end of 2013 and 59 rigs (46 oil and 13 natural gas) as of the end of September 2014. EIA estimates the percentage of electricity fueled by natural gas to be 27% in the nine months ended September 30, 2014 and 2013, and forecasts the percentage at 27% for all of 2014 and 28% in 2015, influenced largely by the expected price of natural gas compared to the expected price of coal. Industry sources have indicated that a natural gas price above $4.50 per Mcf for some period of time will probably cause even more power producers to switch back to coal from natural gas, which in effect creates limits to how far natural gas prices can rise until such time as demand for natural gas increases from other sources. The demand for natural gas is expected to continue to increase as the announced petrochemical facilities are constructed and power producers convert to consuming natural gas to reduce emissions to ever tighter emission regulations and standards. Several companies are planning to build liquefaction capacity to export liquefied natural gas due to significantly higher natural gas prices in Europe and Asia with one such plant having been announced to come online in 2015.

Should the recent price decline in oil continue, it would negatively impact our future revenues, earnings and liquidity, cause impairment write-downs of the carrying value of our oil and natural gas properties, reduce proved reserves, create issues with financial ratio compliance, and lead to a reduction of the borrowing base associated with our Credit Agreement, depending on the longevity and severity of such price weakness. As required by the full cost accounting rules, we performed our ceiling test calculation as of September 30, 2014 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. Based on the results of that calculation, we were not required to record a write-down of the carrying value of our oil and natural gas properties at September 30, 2014. We will perform the ceiling test calculation again as of December 31, 2014. If WTI and Brent prices remain at current levels (high $70s to low $80s) through the remainder of 2014, we estimate that we could recognize a non-cash ceiling test write-down in the fourth quarter of 2014. If WTI and Brent prices remain at current levels (high $70s to low $80s) on a sustained basis during 2015, we could have further non-cash ceiling test write-downs in 2015.

In August 2014, the Parent Company received notification from the EPA that it had lifted the suspension and proposed debarment notices issued previously by the EPA in November 2013. The Notices were directed to only the Parent Company and did not name or apply to our 100%-owned subsidiaries. Accordingly, the drilling and leasing operations of our 100%-owned subsidiary, Energy VI, were not impacted by Notices, nor were the Parent Company's drilling, exploration and production operations impacted on its existing Federal leases. See Part I, Item 1, *Financial Statements – Note 11 – Contingencies,* of this Form 10-Q for additional information.

In May 2014, we received notice from the BOEM that reinstitutes the Parent Company's eligibility for a waiver of certain supplemental bonding for potential offshore decommissioning, plugging and abandonment liabilities. The notice applies to the Parent Company only. Our 100%-owned subsidiary, Energy VI, continues to require supplemental bonding for potential offshore decommissioning, plugging and abandonment liabilities as required by the BOEM's procedures. See Part I, Item 1, *Financial Statements – Note 11 – Contingencies,* of this Form 10-Q for additional information.

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. Four of the five underwriters have not paid in accordance with the Fifth Circuit ruling. We filed a lawsuit in September 2014 against these four underwriters for amounts owed, interest, attorney fees and damages. After receiving reimbursements applied against our remaining Energy Package limits, reimbursement from one of the underwriters of the Excess Policies and adjustments to claims, the estimated potential reimbursement of removal-of-wreck costs is approximately \$35 million, plus interest at 18%, attorney fees and damages, if any. See Part I, Item 1, *Financial Statements – Note 11 – Contingencies,* of this Form 10-Q for additional information.

As described in Part I, Item 1, *Financial Statements – Note 1 – Basis of Presentation,* of this Form 10-Q, in the fourth quarter of 2013, we identified that we had been receiving an erroneous conversion factor from a third party that had the effect of understating natural gas production in prior periods. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the three and nine months ended September 30, 2013 were: an increase in natural gas production volumes of 237 MMcf and 754 MMcf, respectively (with no corresponding increase in revenue); an increase in DD&A expense of \$0.6 million and \$2.1 million, respectively; and a decrease in net income of \$0.4 million and \$1.4 million, respectively. The additional volumes would have revised average realized prices to \$56.94 per Boe from the reported \$57.49 per Boe for the nine months ended September 30, 2013.

Many changes in laws, regulations, guidance, interpretations and policy continue to be proposed and issued in our industry. The process for obtaining offshore drilling permits, especially deepwater drilling permits, has expanded and lengthened in the past few years. The most significant regulation changes in recent years are regulations related to potential environmental impacts, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time to obtain drilling permits and increases the cost of operations. Also, the regulations have changed related to plugging and abandonment of offshore wells and related infrastructure considerably, driving up both the time and cost to perform the work. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time.

Results of Operations

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014(1)	2013	Change	%	2014(1)	2013	Change	%
	(In thousands, except percentages and per share data)				(In thousands, except percentages and per share data)			
Financial:								
Revenues:								
Oil	$ 167,194	$ 184,087	$ (16,893)	(9.2)%	$ 523,323	$ 550,329	$ (27,006)	(4.9)%
NGLs	16,950	16,505	445	2.7%	57,538	50,631	6,907	13.6%
Natural gas	48,359	43,588	4,771	10.9%	167,801	136,520	31,281	22.9%
Other	2,018	375	1,643	NM	3,369	1,680	1,689	100.5%
Total revenues	234,521	244,555	(10,034)	(4.1)%	752,031	739,160	12,871	1.7%
Operating costs and expenses:								
Lease operating expenses	71,732	67,346	4,386	6.5%	189,116	194,935	(5,819)	(3.0)%
Production taxes	1,794	1,807	(13)	(0.7)%	5,628	5,375	253	4.7%
Gathering and transportation	4,115	3,611	504	14.0%	13,396	12,663	733	5.8%
Depreciation, depletion, amortization and accretion	128,671	104,143	24,528	23.6%	380,213	312,911	67,302	21.5%
General and administrative expenses	21,007	20,024	983	4.9%	64,277	60,979	3,298	5.4%
Derivative (gain) loss	(13,781)	15,659	(29,440)	NM	6,790	6,186	604	9.8%
Total costs and expenses	213,538	212,590	948	0.4%	659,420	593,049	66,371	11.2%
Operating income	20,983	31,965	(10,982)	(34.4)%	92,611	146,111	(53,500)	(36.6)%
Interest expense, net of amounts capitalized	19,592	18,800	792	4.2%	58,281	56,620	1,661	2.9%
Other income	197	9,062	(8,865)	NM	205	9,075	(8,870)	NM
Income before income tax expense	1,588	22,227	(20,639)	(92.9)%	34,535	98,566	(64,031)	(65.0)%
Income tax expense	904	8,033	(7,129)	(88.7)%	12,825	35,358	(22,533)	(63.7)%
Net income	$ 684	$ 14,194	$ (13,510)	(95.2)%	$ 21,710	$ 63,208	$ (41,498)	(65.7)%
Basic and diluted earnings per common share	$ 0.01	$ 0.19	$ (0.18)	(94.7)%	$ 0.28	$ 0.83	$ (0.55)	(66.3)%

(1) In the third quarter of 2014, we increased our interest in Fairway; in the second quarter of 2014, we acquired the Woodside Properties; and in the fourth quarter of 2013, we acquired the Callon Properties.

NM - Not meaningful

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014(1)	2013	Change	% (2)	2014(1)	2013	Change	% (2)
Operating: (3)								
Net sales:								
Oil (MBbls)	1,758	1,725	33	1.9%	5,346	5,226	120	2.3%
NGLs (MBbls)	506	494	12	2.4%	1,544	1,520	24	1.6%
Natural gas (MMcf)	12,183	11,924	259	2.2%	36,951	36,486	465	1.3%
Total oil equivalent (MBoe)	4,295	4,207	88	2.1%	13,049	12,828	221	1.7%
Total natural gas equivalents (MMcfe)	25,770	25,241	529	2.1%	78,291	76,967	1,324	1.7%
Average daily equivalent sales (Boe/day)	46,684	45,727	957	2.1%	47,797	46,989	808	1.7%
Average daily equivalent sales (Mcfe/day)	280,105	274,364	5,741	2.1%	286,781	281,932	4,849	1.7%
Average realized sales prices:								
Oil ($/Bbl)	$ 95.10	$ 106.70	$ (11.60)	(10.9)%	$ 97.89	$ 105.30	$ (7.41)	(7.0)%
NGLs ($/Bbl)	33.47	33.39	0.08	0.2%	37.26	33.30	3.96	11.9%
Natural gas ($/Mcf)	3.97	3.66	0.31	8.5%	4.54	3.74	0.80	21.4%
Oil equivalent ($/Boe)	54.13	58.04	(3.91)	(6.7)%	57.38	57.49	(0.11)	(0.2)%
Natural gas equivalent ($/Mcfe)	9.02	9.67	(0.65)	(6.7)%	9.56	9.58	(0.02)	(0.2)%
Average per Boe ($/Boe):								
Lease operating expenses	$ 16.70	$ 16.01	$ 0.69	4.3%	$ 14.49	$ 15.20	$ (0.71)	(4.7)%
Gathering and transportation	0.96	0.86	0.10	11.6%	1.03	0.99	0.04	4.0%
Production costs	17.66	16.87	0.79	4.7%	15.52	16.19	(0.67)	(4.1)%
Production taxes	0.42	0.43	(0.01)	(2.3)%	0.43	0.42	0.01	2.4%
DD&A	29.96	24.76	5.20	21.0%	29.14	24.39	4.75	19.5%
General and administrative expenses	4.89	4.76	0.13	2.7%	4.93	4.75	0.18	3.8%
	$ 52.93	$ 46.82	$ 6.11	13.0%	$ 50.02	$ 45.75	$ 4.27	9.3%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$ 2.78	$ 2.67	$ 0.11	4.1%	$ 2.42	$ 2.53	$ (0.11)	(4.3)%
Gathering and transportation	0.16	0.14	0.02	14.3%	0.17	0.16	0.01	6.3%
Production costs	2.94	2.81	0.13	4.6%	2.59	2.69	(0.10)	(3.7)%
Production taxes	0.07	0.07	—	—	0.07	0.07	—	—
DD&A	4.99	4.13	0.86	20.8%	4.86	4.07	0.79	19.4%
General and administrative expenses	0.82	0.79	0.03	3.8%	0.82	0.79	0.03	3.8%
	$ 8.82	$ 7.80	$ 1.02	13.1%	$ 8.34	$ 7.62	$ 0.72	9.4%

(1) In the third quarter of 2014, we increased our interest in Fairway; in the second quarter of 2014, we acquired the Woodside Properties; and in the fourth quarter of 2013, we acquired the Callon Properties.

(2) Variance percentages are calculated using rounded figures and may result in slightly different figures for comparable data.

(3) 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.

Volume measurements:

Boe - barrel of oil equivalent
Boe/d - barrel of oil equivalent per day
MBbls - thousand barrels for crude oil, condensate or NGLs
MBoe - thousand barrels of oil equivalent

Mcfe - thousand cubic feet equivalent
Mcfe/d - thousand cubic feet equivalent per day
MMcf - million cubic feet
MMcfe - million cubic feet equivalent

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014	2013	Change	%	2014	2013	Change	%
Wells drilled (gross):								
Offshore	—	3	(3)	(100.0)%	3	6	(3)	(50.0)%
Onshore	6	10	(4)	(40.0)%	28	33	(5)	(15.2)%
Productive wells drilled (gross)								
Offshore	—	3	(3)	(100.0)%	3	5	(2)	(40.0)%
Onshore	6	10	(4)	(40.0)%	27	33	(6)	(18.2)%

Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013

Revenues. Total revenues decreased $10.0 million to $234.5 million for the third quarter of 2014 as compared to the third quarter of 2013. Oil revenues decreased $16.9 million, or 9.2%, NGLs revenues increased $0.4 million, or 2.7%, natural gas revenues increased $4.8 million, or 10.9%, and other revenues increased $1.7 million. The oil revenue decrease was attributable to a 10.9% decrease in the average realized sales price to $95.10 per barrel for the third quarter of 2014 from $106.70 per barrel for the third quarter of 2013, partially offset by a 1.9% increase in sales volumes. The NGLs revenue increase was attributable to an increase of 2.4% in sales volumes and a 0.2% increase in the average realized sales price to $33.47 per barrel for the third quarter of 2014 from $33.39 per barrel for the third quarter of 2013. The increase in natural gas revenue resulted from an 8.5% increase in the average realized natural gas sales price to $3.97 per Mcf for the third quarter of 2014 from $3.66 per Mcf for the third quarter of 2013 and from an increase of 2.2% in sales volumes. We experienced increases in production from the A-5 well at Mississippi Canyon 243 (Matterhorn), the A-14 well at Ship Shoal 349 (Mahogany), the return to production of Mississippi Canyon 506 (Wrigley), increases at Fairway due to the plant turnaround in 2013, and new production from both Medusa and Neptune fields. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestitures of certain fields in 2013. Production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 0.6 million barrels of oil equivalent (“MMBoe”) during the third quarter of 2014 which occurred at multiple locations. During the third quarter of 2013, we experienced production deferrals of 0.8 MMBoe.

Revenues from oil and liquids as a percent of our total revenues were 78.5% for the third quarter of 2014 compared to 82.0% for the third quarter of 2013 period. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 35.2% for the third quarter of 2014 compared to 31.3% for the third quarter of 2013 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, increased $4.4 million to $71.7 million in the third quarter of 2014 compared to the prior year period. On a per Boe basis, lease operating expenses increased to $16.70 per Boe during the third quarter of 2014 compared to $16.01 per Boe during the comparable 2013 period. On a component basis, base lease operating expenses increased $6.9 million primarily due to more downhole well work in our West Texas onshore operations, increased expenses due to acquisitions, and lower product handling, maintenance and operations fees charged out to a third party at Mississippi Canyon 243. Partially offsetting the increase in base lease operating expenses was a decrease in facilities maintenance expenses of $1.8 million, which was primarily due to the Yellowhammer plant turnaround performed in the third quarter of 2013. The changes in the other components were a decrease of $0.3 million in insurance premiums, a decrease of net expense of $0.3 million of hurricane related expenses and insurance reimbursements, and a decrease of $0.1 million of workovers expense.

Production taxes. Production taxes were flat in the third quarter of 2014 compared to the third quarter of 2013. Most of our production is from federal waters where no production taxes are imposed. Our onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.5 million to $4.1 million for the third quarter of 2014 compared to the third quarter of 2013.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $29.96 per Boe for the third quarter of 2014 from $24.76 per Boe for the third quarter of 2013. On a nominal basis, DD&A increased to $128.7 million for the third quarter of 2014 from $104.1 million for the third quarter of 2013. DD&A on a per Boe and nominal basis increased in part due to increases in the full cost pool from capital expenditures and estimated future development costs. Our focus on expanding deepwater exploration and development necessarily increases costs prior to increasing proved reserves, leading to an increase in the rate.

General and administrative expenses. G&A increased to $21.0 million for the third quarter of 2014 from $20.0 million for the third quarter of 2013 primarily due to increases in salary and other compensation related expenses. G&A on a per Boe basis was $4.89 per Boe for the third quarter of 2014, compared to $4.76 per Boe for the third quarter of 2013.

Derivative (gain) loss. For the third quarter of 2014 and 2013, our derivative positions resulted in a net gain of $13.8 million and a net loss of $15.7 million, respectively, and relate to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices. Although the open contracts relate to production for future periods, changes in the fair value for all open contracts are recorded at the end of the respective reporting period. For additional information about our derivatives, refer to Part I, Item 1, *Financial Statements – Note 4 – Derivative Financial Instruments,* of this Form 10-Q.

Other income. During the third quarter of 2014, other income was $0.2 million. During the third quarter of 2013, other income of $9.1 million consisted primarily of net proceeds received in conjunction with a payment to us for an option exercised by a counterparty.

Interest expense. Interest expense incurred for the third quarter of 2014 and 2013 was $21.8 million and $21.4 million, respectively, primarily attributable to a higher average balance on our revolving bank credit facility in the third quarter of 2014 compared to the third quarter of 2013. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both third quarters of 2014 and 2013. During the third quarter of 2014 and 2013, $2.2 million and $2.6 million, respectively, of interest was 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 2013.

Income tax expense. Income tax expense was $0.9 million for the third quarter of 2014 compared to $8.0 million for the third quarter of 2013, primarily attributable to lower pre-tax income. Our effective tax rate for the third quarter of 2014 was not meaningful due to adjustments for a revised estimated effective tax rate computed on a year-to-date basis. Our effective tax rate for the third quarter of 2013 was 36.1% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Revenues. Total revenues increased $12.9 million to $752.0 million for the nine months ended September 30, 2014 as compared to the same period in 2013. Oil revenues decreased $27.0 million, or 4.9%, NGLs revenues increased $6.9 million, or 13.6%, natural gas revenues increased $31.3 million, or 22.9%, and other revenues increased $1.7 million. The oil revenue decrease was attributable to a 7.0% decrease in the average realized sales price to $97.89 per barrel for the nine months ended September 30, 2014 from $105.30 per barrel for the prior year period, partially offset by a 2.3% increase in sales volumes. The NGLs revenue increase was attributable to a 11.9% increase in the average realized sales price to $37.26 per barrel for the nine months ended September 30, 2014 from $33.30 per barrel for the prior year period and from an increase of 1.6% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 21.4% increase in the average realized natural gas sales price to $4.54 per Mcf in the nine months ended September 30, 2014 from $3.74 per Mcf for the prior year period and from an increase of 1.3% in sales volumes from the comparable period. We experienced increases in production from the A-5 well at Mississippi Canyon 243 (Matterhorn), the A-14 well at Ship Shoal 349 (Mahogany), the return to production of Mississippi Canyon 506 (Wrigley), increases at Fairway due to the plant turnaround in the third quarter of 2013, and new production from both Medusa and Neptune fields. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestitures of certain fields in 2013. The production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 1.8 MMBoe during the nine months ended September 30, 2014. Specifically, production at Mississippi Canyon 506 (Wrigley) was deferred as a result of maintenance at the host platform and comprised approximately 24% of the deferred production. The Wrigley field has currently resumed production. Production from selected wells at Ship Shoal 349 (Mahogany) was deferred due to closure of a pipeline, a rig move and well work. In addition, weather was a contributing factor in the first quarter of 2014 for production declines at West Texas and at selected offshore fields. The balance of the deferred production occurred at multiple locations. During the nine months ended September 30, 2013, we experienced production deferrals of 1.5 MMBoe, which included the pipeline outage at Mississippi Canyon 506 (Wrigley).

Revenues from oil and liquids as a percent of our total revenues were 77.2% for the nine months ended September 30, 2014 compared to 81.3% for the comparable 2013 period. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 38.1% for the nine months ended September 30, 2014 compared to 31.6% for the comparable 2013 period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workovers and maintenance expenses on our facilities, as well as hurricane related expenses and insurance reimbursements, decreased $5.8 million to $189.1 million in the nine months ended September 30, 2014 compared to the prior year period. On a per Boe basis, lease operating expenses decreased to $14.49 per Boe during the nine months ended September 30, 2014 compared to $15.20 per Boe during the comparable 2013 period. On a component basis, workovers decreased $16.0 million, insurance premiums decreased $3.5 million, facilities maintenance decreased $1.3 million and hurricane related expenses and insurance reimbursements decreased by $1.1 million. The decrease in workover costs was primarily due to a rig workover at Main Pass 69 in the nine months ended September 30, 2013. No costs of this nature were incurred during the nine months ended September 30, 2014. Partially offsetting the decreases in the other component costs were net increases in base lease operating expenses of $16.1 million. Base lease operating expenses were higher primarily due to more downhole well work in our West Texas onshore operations, increased expenses due to acquisitions, lower product handling, maintenance and operations fees charged out to a third party at Mississippi Canyon 243, increases at Ship Shoal 349 (Mahogany) for contract labor and materials, and increased expenses at High Island 22, which has a new well beginning production in October 2014.

Production taxes. Production taxes increased $0.3 million to $5.6 million in the nine months ended September 30, 2014 compared to the prior year period primarily due to onshore activities. Most of our production is from federal waters where no production taxes are imposed. Our onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.7 million to $12.7 million for the nine months ended September 30, 2014 compared to the prior year period primarily due to escalation in third-party transportation fees.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $29.14 per Boe for the nine months ended September 30, 2014 from $24.39 per Boe in the prior year period. On a nominal basis, DD&A increased to $380.2 million for the nine months ended September 30, 2014 from $312.9 million in the prior year period. DD&A on a per Boe and nominal basis increased in part due to increases in the full cost pool from capital expenditures and estimated future development costs. Our focus on expanding deepwater exploration and development necessarily increases costs prior to increasing proved reserves, leading to an increase in the rate.

General and administrative expenses. G&A increased to $64.3 million for the nine months ended September 30, 2014 from $61.0 million for the prior year period primarily due to increases in salary expenses, other compensation expenses and contract labor costs. G&A on a per Boe basis was $4.93 per Boe for the nine months ended September 30, 2014, compared to $4.75 per Boe for the prior year period.

Derivative (gain) loss. For the nine months ended September 30, of 2014 and 2013, our derivative positions resulted in a net loss of $6.8 million and $6.2 million, respectively, and relate to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices. Although the open contracts relate to production for future periods, changes in the fair value for all open contracts are recorded at the end of the respective reporting period. For additional information about our derivatives, refer to Part I, Item 1, *Financial Statements – Note 4 – Derivative Financial Instruments,* of this Form 10-Q.

Other income. During the nine months ended September 30, 2014, other income was $0.2 million. During the nine months ended September 30, 2013, other income of $9.1 million consisted primarily of net proceeds received in conjunction with a payment to us for an option exercised by a counterparty.

Interest expense. Interest expense incurred was $64.7 million for the nine months ended September 30, 2014 compared to $64.2 million for the prior year period primarily attributable to a higher average balance on our revolving bank credit facility. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both the first half of 2014 and 2013. During the nine months ended September 30, 2014 and 2013, $6.4 million and $7.5 million, respectively, of interest was 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 2013.

Income tax expense. Income tax expense was $12.8 million for the nine months ended September 30, 2014 compared to $35.4 million for the same period of 2013, primarily attributable to lower pre-tax income. Our effective tax rate for the nine months ended September 30, 2014 was 37.1% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes and other permanent items. Our effective tax rate for the nine months ended September 30, of 2013 was 35.9% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes.

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 and pay dividends. We have funded such activities with cash on hand, net cash provided by operating activities, sales of property, securities offerings and bank borrowings. These sources of liquidity have historically been sufficient to fund our ongoing cash requirements.

Cash flow and working capital. Net cash provided by operating activities for the nine months ended September 30, 2014 was $424.9 million compared to $475.8 million for the comparable 2013 period. Cash flows from operating activities, before changes in working capital and ARO settlements, were $414.9 million in the first nine months of 2014, a decrease of $2.0 million compared to the $416.9 million generated over the same time period in 2013. The change in cash flows excluding working capital and ARO settlements was primarily due to increased payments on derivative settlements and cash received in 2013 from an option exercised by a counterparty, partially offset by higher revenues. Our combined average realized sales price per Boe was approximately the same as in the comparable 2013 period, with lower average realized sales oil prices being offset by higher average realized natural gas and NGL's sales prices. Our combined production of oil, NGLs and natural gas on a Boe basis during the nine months ended September 30, 2014 increased 1.7% from the comparable 2013 period.

The changes in working capital and ARO settlements led to a net reduction of $49.0 million in net cash provided by operating activities between the two periods. The reduction was primarily caused by large income tax refunds received in the 2013 period due to carryback of tax-based net operating losses and higher receivable collections received in the 2013 period. At the beginning of 2013, receivable balances were higher than historical trends and led to higher collections in 2013. For the 2014 period, receivable balances have been fairly constant. Partially offsetting this decrease was the release of funds held in escrow accounts in the 2014 period due to the utilization of bonds to fulfill our contractual ARO obligation with Total E&P USA, contrasted to the 2013 period when funds were paid into the Total E&P USA escrow account, the release of escrow funds related to the ARO for the Eugene Island 205/89 field and reductions in ARO settlements. Escrowed deposits are included within *Prepaid and Other Assets* on the Condensed Consolidated Statements of Cash Flows.

Net cash used in investing activities during the nine months ended September 30, 2014 and 2013 was $457.6 million and $419.9 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. The increase is primarily attributable to the purchase of the Woodside Properties and increasing our ownership interest at Fairway in 2014, partially offset by decreases in both onshore and offshore drilling and development activities. During the nine months ended September 30, 2013, net proceeds of $4.6 million were related to sales of certain property interests and receipt of funds for an option exercised by a counterparty. There were no acquisitions of significance completed in the comparable 2013 period.

Net cash provided by financing activities was $34.1 million for the nine months ended September 30, 2014 and net cash used in financing activities was $53.0 million for the nine months ended September 30, 2013. The net cash provided for the nine months ended September 30, 2014 was primarily attributable to net borrowings on our revolving bank credit facility of $57.0 million and partially offset by dividend payments of $22.7 million. The purchase of the Woodside properties and increasing our ownership interest at Fairway was funded through borrowings on the revolving bank credit facility and cash on hand. The net cash used for the nine months ended September 30, 2013 was primarily attributable to net repayments of $33.0 million on our revolving bank credit facility and dividend payments of $19.6 million.

At September 30, 2014, we had a cash balance of $17.2 million and $402.4 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $750.0 million. The borrowing base was reaffirmed at $750.0 million effective October 22, 2014.

Credit Agreement and long-term debt. At September 30, 2014 and December 31, 2013, $347.0 million and $290.0 million, respectively, were outstanding under our revolving bank credit facility. During the nine months ended September 30, 2014, the outstanding borrowings on our revolving bank credit facility ranged from $242.0 million to $389.0 million. At September 30, 2014 and December 31, 2013, $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. For additional information about our long-term debt, refer to Part I, Item 1, *Financial Statements – Note 5 – Long-Term Debt,* of this Form 10-Q.

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, including a minimum current ratio and a maximum leverage ratio, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement and all applicable covenants related to the 8.50% Senior Notes as of September 30, 2014.

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 and interest rate risk from floating interest rates on our revolving bank credit facility. As of September 30, 2014, our derivative instruments outstanding consisted of oil contracts relating to approximately 0.6 million barrels ("MMBbls") of our anticipated production for the balance of 2014. See Part I, Item 1, *Financial Statements – Note 4 – Derivative Financial Instruments,* of this Form 10-Q for additional information.

Insurance Claims and Insurance Coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which $156.2 million has been collected through September 30, 2014. We received a ruling in our favor from the Fifth Circuit concerning the underwriters' interpretation of our Excess Policies related to the coverage of removal-of-wreck costs incurred due to Hurricane Ike. The underwriters filed three separate briefs requesting a rehearing or a certification to the Texas Supreme Court, all of which the Court denied. One underwriter requested a rehearing with the District Court (appealing the Fifth Circuit's decision), which was denied. Four of the five underwriters of our Excess Policies have not paid in accordance with the Fifth Circuit ruling and, as a result, we filed a lawsuit in September 2014 seeking payment on the remaining claims of approximately $35.0 million, plus interest at 18%, attorney fees and damages. Removal-of-wreck costs and insurance recoveries related to removal-of-wreck costs are recorded in *Oil and natural gas properties and equipment* on the Condensed Consolidated Balance Sheets. See Part I, Item 1, *Financial Statements – Note 11 – Contingencies,* of this Form 10-Q for additional information.

We currently carry multiple layers of insurance coverage in our Energy Package covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. We 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, 2015. 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.

We estimate that a substantial majority of our estimated future net revenues attributable to our Gulf of Mexico properties are covered under our current insurance policies for named windstorm damage. There are certain other properties we have decided not to have full coverage for named windstorm damage as part of our risk assessment process.

Our general and excess liability policies are effective until May 1, 2015 and provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE. We qualify to self-insure for $54.0 million of this amount and the remaining $96.0 million is covered by insurance.

Although we were able to renew our Energy Package and our general and excess liability policies in the second quarter of 2014 and have not been informed otherwise, in the future, our insurers may not continue to offer this type and level of coverage to us, 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.

See Part I, Item 1, *Financial Statements – Note 11 – Contingencies,* of this Form 10-Q for information related to notifications from the BOEM concerning reinstatement of the Parent Company's waiver of supplemental bonding requirements for potential offshore decommissioning liabilities.

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:

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(In thousands)	
Increased interest in Fairway	$ 18,152	$ —
Acquisition of Woodside Properties	53,363	—
Acquisition of Callon Properties (1)	576	—
Exploration (2)	143,585	149,392
Development (2)	217,009	246,105
Seismic, capitalized interest, other leasehold costs	22,783	27,595
Acquisitions and investments in oil and gas property/equipment	$ 455,468	$ 423,092

(1) The amount in 2014 represents adjustments to the purchase price for post-effective date adjustments.
(2) Reported geographically in the subsequent table.

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

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(In thousands)	
Conventional shelf	$ 104,777	$ 132,428
Deepwater	119,196	82,336
Deep shelf	23,574	57,918
Onshore	113,047	122,815
Exploration and development capital expenditures	$ 360,594	$ 395,497

Our capital expenditures for the nine months ended September 30, 2014 and 2013 were financed by cash flow from operating activities, borrowings on our revolving bank credit facility, sales of property interests and cash on hand.

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

	Nine Months Ended September 30,			
	2014		2013	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	—	—	4	4.0
Non-productive	—	—	—	—
Onshore wells:				
Productive	17	16.3	28	27.9
Non-productive	—	—	—	—
Total development wells	17	16.3	32	31.9
Exploration wells:				
Offshore wells:				
Productive	3	2.2	1	1.0
Non-productive	—	—	1	1.0
Onshore wells:				
Productive	10	9.9	5	4.9
Non-productive	1	1.0	—	—
Total exploration wells	14	13.1	7	6.9
Total wells	31	29.4	39	38.8

Exploration activities. During the nine months ended September 30, 2014, three offshore exploration wells were completed. The Mississippi Canyon 243 (Matterhorn) A-5 side-track well was brought online during the first quarter of 2014 and provided production volumes even though the intent was for it to be a water-injection well. In September 2014, the A-5 side-track well was converted to a water-injection well as originally planned. The Ship Shoal 349 (Mahogany) A-15 well was brought online during the second quarter of 2014. During the first quarter of 2014, the completion operations on the Mississippi Canyon 698 (Big Bend) well were finalized with first production expected in the second half of 2015. During the first nine months of 2014, we completed ten exploration onshore wells, eight of which were vertical wells and two of which were horizontal wells.

Acquisitions and funding. We intend to continue to pursue acquisitions and joint venture opportunities during 2014 and beyond should we identify attractive opportunities. For example, in the second quarter of 2014, we completed the acquisition of the Woodside Properties and in the fourth quarter of 2013, we completed the acquisition of the Callon Properties as described in Part I, Item 1, *Financial Statements – Note 2 – Acquisitions and Divestitures,* 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 nine months ended September 30, 2014, in East Texas at our Star Project, we reassigned approximately 160,000 gross acres back to our original assignor. During the nine months ended September 30, 2014, we did not have any divestitures. During 2013, we sold our interests in various fields. See Part I, Item 1, *Financial Statements – Note 2 – Acquisitions and Divestitures,* of this Form 10-Q for additional information.

Capital Expenditure Budget for 2014. Our revised capital expenditure budget for 2014 is $635.0 million. The revised budget includes the acquisitions completed so far this year. The budget includes 50% for exploration, 37% for development and 13% for other items. Geographically, the budget is split 66% for offshore, 9% for completed offshore acquisitions and 25% for onshore. The budget does not include any potential acquisitions. We will continue to evaluate and bid on acquisition opportunities as they arise. We anticipate funding our 2014 capital budget, any potential acquisitions and other expenditures with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility, proceeds from divestitures, if any, and by accessing the capital markets to the extent necessary. Our 2014 capital budget is subject to change as conditions warrant.

Income taxes. During the nine months ended September 30, 2014, we made no income tax payments and received $3.0 million in refunds. For the remainder of 2014, we expect a substantial amount of our income tax will be deferred and expect payments, if any, to be primarily related to state taxes. During the nine months ended September 30, 2013, we made no income tax payments and received $59.1 million of refunds. The refunds were primarily attributable to tax loss carrybacks to 2010 and 2011, and refunds of 2012 estimated federal tax payments. We have $263.4 million of net operating loss carryforward (tax basis) available to offset future federal taxable income in 2014 and forward. We also have $12.1 million of alternative minimum tax credit carryforwards available to be utilized in 2014 and forward.

Dividends. See Part I, Item 1, *Financial Statements – Note 10 – Dividends,* of this Form 10-Q.

Contractual obligations. Updated information on certain contractual obligations is provided in Part I, Item 1,*Financial Statements – Note 3 – Asset Retirement Obligations* and *Note 5 – Long-Term Debt,* of this Form 10-Q. As of September 30, 2014, drilling rig commitments were approximately $25.6 million compared to $21.5 million as of December 31, 2013. The current drilling rig commitments expire within one year from September 30, 2014. Except for scheduled utilization, other contractual obligations as of September 30, 2014 did not change materially from the disclosures in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations,* of our Annual Report on Form 10-K for the year ended December 31, 2013.

Critical Accounting Policies

Our significant accounting policies are summarized in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2013. Also refer to Part 1, Item 1, *Financial Statements – Note 1 – Basis of Presentation,* of this Form 10-Q.

Recent Accounting Pronouncements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the nine months ended September 30, 2014 did not change materially from the disclosures in Item 7A,*Quantitative and Qualitative Disclosures About Market Risk,* of our Annual Report on Form 10-K for the year ended December 31, 2013. 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, 2013.

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 and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. We currently have open crude oil derivative contracts to manage a portion of our exposure to commodity price risk from sales of oil for the balance of 2014. As of September 30, 2014, these derivative contracts had a notional quantity of 0.6 MMBbls. We do not designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of volatile oil prices, they may also limit future income from favorable price movements. See Part I, Item 1, *Financial Statements – Note 4 – Derivative Financial Instruments,* of this Form 10-Q for additional information.

Interest Rate Risk. As of September 30, 2014, we had $347.0 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 1.75% to 2.75% depending on the amount outstanding. We currently do not have any derivative instruments related to interest rates.

Item 4. Controls and Procedures

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

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our CEO and CFO have each concluded that as of September 30, 2014 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended September 30, 2014, 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, 2013, 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, 2013 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, 2013.

Item 6. Exhibits

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

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on November 6, 2014.

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))
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: November 6, 2014

/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: November 6, 2014

/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 September 30, 2014 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: November 6, 2014

/s/ Tracy W. Krohn

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

Date: November 6, 2014

/s/ John D. Gibbons

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