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, 2013

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 5, 2013, there were 75,277,080 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2013	December 31, 2012
	(In thousands, except share data) (Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 15,227	$ 12,245
Receivables:		
Oil and natural gas sales	85,221	97,733
Joint interest and other	31,492	56,439
Income taxes	—	47,884
Total receivables	116,713	202,056
Restricted cash and cash equivalents	16,459	—
Prepaid expenses and other assets	32,850	25,822
Total current assets	181,249	240,123
Property and equipment – at cost:		
Oil and natural gas properties and equipment (full cost method, of which $129,584 at September 30, 2013 and $123,503 at December 31, 2012 were excluded from amortization)	7,120,086	6,694,510
Furniture, fixtures and other	21,325	21,786
Total property and equipment	7,141,411	6,716,296
Less accumulated depreciation, depletion and amortization	4,950,768	4,655,841
Net property and equipment	2,190,643	2,060,455
Restricted deposits for asset retirement obligations	34,966	28,466
Other assets	16,842	19,943
Total assets	$ 2,423,700	$ 2,348,987
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 129,988	$ 123,885
Undistributed oil and natural gas proceeds	41,278	37,073
Asset retirement obligations	95,014	92,630
Accrued liabilities	51,048	21,021
Total current liabilities	317,328	274,609
Long-term debt	1,052,984	1,087,611
Asset retirement obligations, less current portion	267,093	291,423
Deferred income taxes	177,404	145,249
Other liabilities	15,859	8,908
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at September 30, 2013 and December 31, 2012	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,146,253 issued and 75,277,080 outstanding at September 30, 2013, and 78,118,803 issued and 75,249,630 outstanding at December 31, 2012	1	1
Additional paid-in capital	404,604	396,186
Retained earnings	212,594	169,167
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	593,032	541,187
Total liabilities and shareholders' equity	$ 2,423,700	$ 2,348,987

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,	
	2013	2012	2013	2012
	(In thousands, except per share data) (Unaudited)			
Revenues	$ 244,555	$ 185,946	$ 739,160	$ 637,345
Operating costs and expenses:				
Lease operating expenses	67,346	53,411	194,935	170,349
Production taxes	1,807	1,353	5,375	4,174
Gathering and transportation	3,611	2,810	12,663	11,140
Depreciation, depletion, amortization and accretion	104,143	77,462	312,911	251,894
General and administrative expenses	20,024	18,691	60,979	62,793
Derivative loss	15,659	24,659	6,186	14,421
Total costs and expenses	212,590	178,386	593,049	514,771
Operating income	31,965	7,560	146,111	122,574
Interest expense:				
Incurred	21,373	14,791	64,157	43,409
Capitalized	(2,573)	(3,383)	(7,537)	(9,899)
Other income	9,062	202	9,075	210
Income (loss) before income tax expense	22,227	(3,646)	98,566	89,274
Income tax expense (benefit)	8,033	(2,175)	35,358	33,959
Net income (loss)	$ 14,194	$ (1,471)	$ 63,208	$ 55,315
Basic and diluted earnings (loss) per common share	$ 0.19	$ (0.02)	$ 0.83	$ 0.73
Dividends declared per common share	$ 0.09	$ 0.08	$ 0.26	$ 0.24

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, 2012	75,250	$ 1	$ 396,186	$ 169,167	2,869	$ (24,167)	$ 541,187
Cash dividends	—	—	—	(19,570)	—	—	(19,570)
Share-based compensation	—	—	8,457	—	—	—	8,457
Other	27	—	(39)	(211)	—	—	(250)
Net income	—	—	—	63,208	—	—	63,208
Balances at September 30, 2013	75,277	$ 1	$ 404,604	$ 212,594	2,869	$ (24,167)	$ 593,032

See Notes to Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2013	2012
	(In thousands) (Unaudited)	
Operating activities:		
Net income	$ 63,208	$ 55,315
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	312,911	251,894
Amortization of debt issuance costs and premium	1,366	2,046
Share-based compensation	8,457	9,137
Derivative loss	6,186	14,421
Cash payments on derivative settlements	(6,855)	(6,960)
Deferred income taxes	31,581	44,465
Changes in operating assets and liabilities:		
Oil and natural gas receivables	12,511	30,320
Joint interest and other receivables	24,947	3,935
Insurance receivables	5,117	500
Income taxes	53,433	(24,327)
Prepaid expenses and other assets	(10,815)	670
Asset retirement obligation settlements	(59,188)	(63,150)
Accounts payable, accrued liabilities and other	32,974	33,223
Net cash provided by operating activities	475,833	351,489
Investing activities:		
Investment in oil and natural gas properties and equipment	(423,092)	(312,372)
Proceeds from sales of assets and other, net	21,011	30,453
Change in restricted cash	(16,459)	(24,026)
Deposit for acquisition	—	(22,800)
Purchases of furniture, fixtures and other	(1,327)	(2,125)
Net cash used in investing activities	(419,867)	(330,870)
Financing activities:		
Borrowings of long-term debt – revolving bank credit facility	335,000	316,000
Repayments of long-term debt – revolving bank credit facility	(368,000)	(314,000)
Debt issuance costs	(164)	(2,081)
Dividends to shareholders	(19,570)	(17,848)
Other	(250)	(209)
Net cash used in financing activities	(52,984)	(18,138)
Increase in cash and cash equivalents	2,982	2,481
Cash and cash equivalents, beginning of period	12,245	4,512
Cash and cash equivalents, end of period	$ 15,227	$ 6,993

See Notes to Condensed Consolidated Financial Statements.

1. Basis of Presentation

Operations. W&T Offshore, Inc. and subsidiaries, referred to herein as "W&T" 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.

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, 2012.

Reclassifications. Certain reclassifications have been made to the prior periods' financial statements to conform to the current presentation. *Deferred income taxes – current asset* was combined with *Prepaid expenses and other assets* on the Balance Sheet, *Income taxes payable* was combined with *Accrued liabilities* on the Balance Sheet, and changes in *Other liabilities* was combined with the changes in *Accounts payable and accrued liabilities* on the Statement of Cash Flows.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Recent Accounting Developments. In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities* which applies to certain items in the statement of financial position (balance sheet), and was further clarified in January 2013 by ASU 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which clarified the scope of ASU 2011-11 to derivative instruments, repurchase agreements and securities lending transactions. The effective date for the amendments is for annual periods beginning after January 1, 2013, and interim periods within those annual periods. ASU 2011-11 requires disclosures of the gross and net amounts for items eligible for offset in the balance sheet. The Company's derivative financial instruments are subject to master netting agreements and the Company records its derivative financial instruments on a gross basis by contract; therefore, the revisions relate to disclosure of the Company's derivative financial instruments on a net basis. Other items of the ASUs were not applicable to the Company.

In February 2013, the FASB issued ASU 2013-04, *Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date,* which requires an entity that is joint and severally liable to measure the obligation as the sum of the amount the entity has agreed with co-obligors to pay and any additional amount it expects to pay on behalf of one or more co-obligors. Required disclosures include a description of the nature of the arrangement, how the liability arose, the relationship with co-obligors and the terms and conditions of the arrangement. The effective date for the amendment is for annual periods beginning after December 15, 2013, and interim periods within those annual periods. The amendment is to be applied retrospectively to all prior periods presented. The Company is currently assessing the impact of ASU 2013-04 to determine the effects on the balance sheet and disclosures, if any.

In July 2013, the FASB issued ASU 2013-11, *Income Taxes (Topic 740); Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a similar Tax Loss, or a Tax Credit Carryforward Exists a consensus of the FASB Emerging Task Force*, which provided guidance on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This guidance requires an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. The amendment is effective for annual periods and interim periods beginning after December 15, 2013. Early adoption is permitted and the amendment is to be applied prospectively. The Company is currently assessing the impact of ASU 2013-11 to determine the effects on the balance sheet and disclosures, if any.

Other income. For the three and nine months ended September 30, 2013, the amounts reported consisted primarily of $9.2 million received in conjunction with a payment to W&T for an option exercised by a counterparty. Partially offsetting the proceeds were related third-party expenses of $0.1 million.

2. Acquisitions and 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 asset retirement obligations ("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 $16.5 million. The transaction was structured as a like-kind exchange under the Internal Revenue Service Code ("IRC") Section 1031 and other applicable regulations, with funds held by a qualified intermediary until replacement purchases are made. Replacement purchases are expected to be consummated within the replacement periods defined under the IRC. The net proceeds are recorded on the Balance Sheet in *Restricted cash and cash equivalents* due to the restrictions on the use of the cash under IRC regulations for like-kind exchanges. In connection with this sale, we reversed $3.9 million of ARO.

2012 Acquisition. On October 5, 2012, we acquired from Newfield Exploration Company and its subsidiary, Newfield Exploration Gulf Coast LLC (together, "Newfield") certain oil and gas leasehold interests in the Gulf of Mexico (the "Newfield Properties"). The Newfield Properties consist of leases covering 78 offshore blocks on approximately 416,000 gross acres (268,000 net acres) (excluding overriding royalty interests). Including adjustments from an effective date of July 1, 2012, the adjusted purchase price was $205.7 million and we assumed the future ARO associated with the Newfield Properties. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand. Subsequently in the same month, the amounts borrowed under our revolving bank credit facility were paid down with funds provided from the issuance of long-term debt in October 2012. See Note 6 for information on long-term debt. The purchase price was finalized during the second quarter of 2013 and no further adjustments are expected. Adjustments to the purchase price of a net increase of $0.2 million were recorded in the nine months ended September 30, 2013.

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

Oil and natural gas properties and equipment	$	237,396
Asset retirement obligations – current		(7,250)
Asset retirement obligations – non-current		(24,414)
Total cash paid	$	205,732

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 for the Newfield Properties acquisition.

Revenues, Net Income and Pro Forma Financial Information — Unaudited

The Newfield Properties were not included in our consolidated results until the closing date of October 5, 2012. For the three months ended September 30, 2013, the Newfield Properties accounted for $31.9 million of revenues, $5.5 million of direct operating expenses, $14.7 million of depreciation, depletion, amortization and accretion ("DD&A") and $4.1 million of income taxes, resulting in $7.6 million of net income. For the nine months ended September 30, 2013, the Newfield Properties accounted for $94.2 million of revenues, $19.6 million of direct operating expenses, $41.1 million of DD&A and $11.7 million of income taxes, resulting in $21.8 million of net income. The net income attributable to these properties does not reflect certain expenses, such as general and administrative ("G&A") expense 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 Newfield Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate. Expenses associated with acquisition activities and transition activities related to the acquisition of the Newfield Properties were less than $0.1 million for the three and nine months ended September 30, 2012.

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, 2012, the unaudited pro forma financial information was computed as if the acquisition of the Newfield Properties had been completed on January 1, 2011. 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 the interim periods, the Newfield Properties' audited historical financial statement for 2011 and the Newfield Properties' unaudited historical financial statements for the 2012 interim periods.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Newfield Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2011. If the transaction had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Newfield; the realized sales prices for oil, natural gas liquids ("NGLs") and natural gas may have been different; and the costs of operating the Newfield 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, 2012	Nine Months Ended September 30, 2012
Revenues	$ 217,714	$ 741,808
Net income	508	59,897
Basic and diluted earnings per common share	0.01	0.79

For the pro forma financial information, certain information was derived from financial records and certain information was estimated.

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

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Revenues (a)	$ 31,768	$ 104,463
Direct operating expenses (a)	9,026	33,089
Insurance and acquisition costs, net (b)	128	444
DD&A (c)	15,757	52,634
Interest expense (d)	3,960	11,881
Capitalized interest (e)	148	634
Income tax expense (f)	1,066	2,467

The sources of information and significant assumptions are described below:

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

(b) Incremental costs for insurance were estimated using the incremental costs to add the Newfield Properties to W&T's insurance programs. The direct operating expenses for the Newfield Properties described above exclude insurance costs. Expenses were reduced for acquisition costs incurred.

(c) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Newfield Properties' costs, reserves and production into our currently existing full cost pool in order to compute such amounts. The purchase price allocation included $13.1 million that was allocated to the pool of unevaluated properties for oil and natural gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties. ARO was estimated by W&T management.

(d) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $205.7 million, which equates to the cash paid including purchase price adjustments and an interest rate of 7.7%, which equates to the effective yield on net proceeds for the additional senior notes issued shortly after the acquisition closed.

(e) Incremental capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings.

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

2012 Divestiture. On May 15, 2012, we sold our 40%, non-operated working interest in the South Timbalier 41 field located in the Gulf of Mexico for $30.5 million with an effective date of April 1, 2012. The transaction was structured as a like-kind exchange under the IRC Section 1031 and other applicable regulations, with funds held by a qualified intermediary until replacement purchases could be executed. Replacement purchases were consummated during 2012. In connection with this sale, we reversed $4.0 million of ARO.

3. Hurricane Remediation and Insurance Claims

During the third quarter of 2008, Hurricane Ike caused substantial damage to certain of our properties and we continue to incur costs and submit claims to our insurance underwriters related to repairing such damage. Our insurance policies in effect on the occurrence date of Hurricane Ike had a retention requirement of $10.0 million per occurrence, which has been satisfied, and coverage policy limits of $150.0 million for property damage due to named windstorms (excluding damage at certain facilities) and $250.0 million for, among other things, removal of wreckage if mandated by any governmental authority.

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection, which arises when our insurance underwriters' adjuster reviews and approves such costs for payment by the underwriters. Claims that have been processed in this manner have customarily been paid on a timely basis.

From the third quarter of 2008 through September 30, 2013, we have received $147.3 million from our insurance underwriters related to Hurricane Ike. See Note 4 for additional information about the impact of hurricane related items on our ARO. See Note 12 for information regarding legal actions taken by certain insurers and the Company.

4. 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, 2012	$ 384,053
Liabilities settled	(59,188)
Accretion of discount	16,236
Disposition of properties	(19,564)
Liabilities incurred	372
Revisions of estimated liabilities due to Hurricane Ike (1)	5,526
Revisions of estimated liabilities – all other (1)	34,672
Balance, September 30, 2013	362,107
Less current portion	95,014
Long-term	$ 267,093

(1) Revisions are primarily due to increases in the scope of work at several offshore locations required by the Bureau of Safety and Environmental Enforcement ("BSEE").

5. 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 7. 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 statement 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, 2013 and 2012, 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 and a portion based on West Texas Intermediate ("WTI") 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. Although our Gulf of Mexico crude oil is based off the WTI crude oil price plus a premium, the realized prices received for our Gulf of Mexico crude oil 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 swap oil 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, 2013, our open commodity derivative contracts were as follows:

		Swaps – Oil			
		Priced off Brent (ICE)		Priced off WTI (NYMEX)	
Termination Period		Notional Quantity (Bbls)	Weighted Average Contract Price	Notional Quantity (Bbls)	Weighted Average Contract Price
2013:	4th quarter	294,400	$ 101.98	520,000	$ 97.38
2014:	1st quarter	180,000	97.38	762,000	97.39
	2nd quarter	172,900	97.38	455,000	97.17
	3rd quarter	165,600	97.38	155,000	97.00
	4th quarter	156,400	97.37	—	—
		969,300	$ 98.77	1,892,000	$ 97.30

Bbls = barrels

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

	September 30, 2013	December 31, 2012
Prepaid and other assets	$ 317	$ —
Accrued liabilities	8,611	6,355
Other liabilities (noncurrent)	439	3,046

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Derivative (gain) loss:				
Realized	$ 4,545	$ 875	$ 6,855	$ 6,960
Unrealized	11,114	23,784	(669)	7,461
Total	$ 15,659	$ 24,659	$ 6,186	$ 14,421

Offsetting Commodity Derivatives. As of September 30, 2013 and December 31, 2012, 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 presents disclosures required by ASU 2011-11 and ASU 2013-01 and 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 as of September 30, 2013 (in thousands):

	Derivative Assets	Derivative Liabilities
Gross amounts presented in the balance sheet	$ 317	$ 9,050
Amounts not offset in the balance sheet	(317)	(317)
Net amounts	$ —	$ 8,733

There were no potential effects of master netting agreements on the fair value of open derivative contracts as of December 31, 2012 due to all open derivative contracts being valued as liabilities.

6. Long-Term Debt

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

	September 30, 2013	December 31, 2012
8.50% Senior Notes	$ 900,000	$ 900,000
Debt premiums, net of amortization	15,984	17,611
Revolving bank credit facility	137,000	170,000
Total long-term debt	1,052,984	1,087,611
Current maturities of long-term debt	—	—
Long-term debt, less current maturities	$ 1,052,984	$ 1,087,611

At September 30, 2013 and December 31, 2012, 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, 2013.

The Fourth Amended and Restated Credit Agreement (the "Credit Agreement") governs our revolving bank credit facility and terminates on May 5, 2015. 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. See Note 13 for information regarding a new credit agreement executed subsequent to September 30, 2013.

At September 30, 2013 and December 31, 2012, we had $0.1 million of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 3.9% for the nine months ended September 30, 2013 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, 2013, our borrowing base was $800.0 million and our borrowing availability was $662.9 million.

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, 2013.

For information about fair value measurements for our 8.50% Senior Notes and revolving bank credit facility, refer to Note 7.

7. Fair Value Measurements

We measure the fair value of our 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 and 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 derivative financial instruments, 8.50% Senior Notes and revolving bank credit facility for the periods indicated (in thousands).

		September 30, 2013		December 31, 2012	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ 317	$ 9,050	$ —	$ 9,401
8.50% Senior Notes	Level 2	—	977,625	—	963,000
Revolving bank credit facility	Level 2	—	137,000	—	170,000

As described in Note 5, our 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 6.

8. 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 on May 7, 2013. As allowed by the Plan, in 2013, 2012 and in 2011, 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. Certain RSUs granted in 2013 (the "2013 RSUs") are subject to performance criteria of Adjusted EBITDA, defined as net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items, adjusted EBITDA as a percent of total revenue ("Adjusted EBITDA Margin") and total shareholder return ("TSR"). The RSUs granted in 2012 (the "2012 RSUs") are subject to performance criteria of earnings per share and TSR, while the RSUs granted in 2011 (the "2011 RSUs") are subject to only earnings per share performance measurement. In 2013 and in prior years, restricted stock was granted to the Company's non-employee directors under the Director Compensation Plan. The restricted stock and RSUs each vest at the end of specified service periods. 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 predetermined performance criteria.

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.

On May 7, 2013, after receiving shareholder approval, 4,000,000 shares of common stock were added to the amount available for issuance under the Plan. At September 30, 2013, there were 5,393,602 shares of common stock available for issuance in satisfaction of awards under the Plan and 519,379 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 stock is 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.

Restricted Stock. As of September 30, 2013, all of the unvested 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 shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. The fair value of restricted stock was estimated by using the Company's closing price on the grant date.

A summary of activity in 2013 related to restricted stock is as follows:

	Restricted Stock	
	Shares	Weighted Average Grant Date Fair Value Per Share
Outstanding restricted shares, December 31, 2012	43,687	$ 18.69
Granted	27,450	12.75
Vested	(27,297)	17.09
Outstanding restricted shares, September 30, 2013	43,840	$ 15.96

Subject to the satisfaction of service conditions, the outstanding restricted shares issued to the non-employee directors as of September 30, 2013 are expected to vest as follows:

	Shares
2014	19,445
2015	15,245
2016	9,150
Total	43,840

The grant date fair value of restricted shares granted during the nine months ended September 30, 2013 and 2012 was $0.3 million and $0.4 million, respectively. The fair value of restricted shares that vested during the nine months ended September 30, 2013 and 2012 was $0.4 million and $0.5 million, respectively.

Restricted Stock Units. As of September 30, 2013, the Company had outstanding RSUs issued to certain employees. Certain 2013 RSUs are subject to pre-defined share performance measures comprised of Adjusted EBITDA and Adjusted EBITDA Margin for 2013 and TSR for defined periods in 2013, 2014 and 2015; therefore, no portion has been determined to be eligible for vesting as of September 30, 2013. A portion of the 2012 RSUs remains subject to the certain pre-defined performance measures of TSR for the defined periods in 2013 and 2014; therefore, this portion will be determined whether eligible for vesting at the end of the respective performance periods. TSR is determined based upon the change in the entity's stock price and dividends for the performance period. The TSR targets are the ranking of the Company's TSR compared to the TSR of certain peer companies. The TSR components have an issuance scale from 0% to 200%. The portion of RSUs subject to TSR performance measurement is disclosed in the second table below.

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. The fair value of the 2011 RSUs, which contained only Company-specific performance measures, was estimated by using the Company's closing price on the grant date.

The majority of RSUs are subject to predetermined performance criteria and all RSUs are subject to service requirements prior to vesting. 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 2013 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding RSUs, December 31, 2012	969,820	$ 22.70
Granted	969,919	13.23
Forfeited	(33,042)	18.86
Outstanding RSUs, September 30, 2013	1,906,697	$ 17.95

Subject to the satisfaction of service conditions, the RSUs outstanding as of September 30, 2013 are eligible to vest in the year indicated in the table below:

	Units
2013 – subject to service requirements	470,536
2014 – subject to service requirements	335,555
2014 – subject to service and other requirements (1)	138,330
2015 – subject to service requirements	23,500
2015 – subject to service and other requirements (2)	657,143
2015 – subject to service and other requirements (3)	281,633
Total	1,906,697

(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 certain Company-specific performance requirements not yet measureable, with awards ranging from 0% to 150% of amounts granted.
(3) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 200% of amounts granted.

The grant date fair value of RSUs granted during the nine months ended September 30, 2013 and 2012 was $12.8 million and $14.2 million, respectively. During the nine months ended September 30, 2013 and 2012, there was no vesting of RSUs.

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,	
	2013	2012	2013	2012
Share-based compensation expense from:				
Restricted stock	$ 99	$ 110	$ 297	$ 324
Restricted stock units	3,408	3,209	8,160	8,813
Total	$ 3,507	$ 3,319	$ 8,457	$ 9,137
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$ 1,227	$ 1,162	$ 2,960	$ 3,198

Unrecognized Share-Based Compensation. As of September 30, 2013, unrecognized share-based compensation expense related to our outstanding restricted shares and RSUs was $0.6 million and $16.1 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2016 for restricted shares and November 2015 for RSUs.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees payable in cash. 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,	
	2013	2012	2013	2012
Share-based compensation expense included in:				
General and administrative—charge to operating income	$ 3,507	$ 3,319	$ 8,457	$ 9,137
Cash-based incentive compensation included in:				
Lease operating expense	724	947	2,864	2,846
General and administrative	2,191	3,048	7,745	4,926
Total charged to operating income	2,915	3,995	10,609	7,772
Total incentive compensation charged to operating income	$ 6,422	$ 7,314	$ 19,066	$ 16,909

9. Income Taxes

Income tax expense of $8.0 million and $35.4 million was recorded during the three and nine months ended September 30, 2013, respectively. Our 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 of 35.0% primarily as a result of state income taxes. Income tax benefit of $2.2 million and income tax expense of $34.0 million was recorded during the three and nine months ended September 30, 2012, respectively. The effective tax rate for the three months ended September 30, 2012 was 59.7%, which exceeded the amount computed at the statutory rate as a result of a decrease in our full year forecasted effective tax rate. Our effective tax rate for the nine months ended September 30, 2012 was 38.0% and differed from the federal statutory rate primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the IRC as a result of loss carrybacks to prior years.

During the three and nine months ended September 30, 2013, we received refunds of $59.1 million and 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 months and nine months ended September 30, 2013, we had less than $0.1 million of accrued interest related to our unrecognized tax benefit. We did not have an unrecognized tax benefit at December 31, 2012. As of September 30, 2013 and December 31, 2012, 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 2009 through 2012 remain open to examination by the tax jurisdictions to which we are subject.

10. 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,	
	2013	2012	2013	2012
Net income (loss)	$ 14,194	$ (1,471)	$ 63,208	$ 55,315
Less portion allocated to nonvested shares	159	90	713	1,128
Net income (loss) allocated to common shares	$ 14,035	$ (1,561)	$ 62,495	$ 54,187
Weighted average common shares outstanding	75,233	74,327	75,221	74,315
Basic and diluted earnings (loss) per common share	$ 0.19	$ (0.02)	$ 0.83	$ 0.73
Shares excluded due to being anti-dilutive (weighted-average)	851	1,866	860	1,823

11. Dividends

During the nine months ended September 30, 2013 and 2012, we paid regular cash dividends per common share of $0.26 and $0.24, respectively. On November 6, 2013, our board of directors declared a cash dividend of $0.10 per common share, payable on December 3, 2013 to shareholders of record on November 18, 2013.

12. Contingencies

Cameron Parish Louisiana Claim. Since 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and its Chief Executive Officer, Tracy W. Krohn, as well as several other defendants unrelated to us. In their lawsuits, plaintiffs alleged that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and they are seeking compensatory and punitive damages. During 2012 and for the nine months ended September 30, 2013, we settled claims with certain landowners and paid $10.0 million and $1.3 million, respectively.

Qui Tam Litigation. On September 21, 2012, the Company was served with a complaint in a *qui tam* action filed under the federal False Claims Act by an employee of a Company contractor. The lawsuit, *United States ex rel. Comeaux v. W&T Offshore, Inc., et al.; CA No. 10-494*, was filed in the United States District Court for the Eastern District of Louisiana, against the Company and three other working interest owners related to claims associated with three of the Company's operated production platforms. A *qui tam* action, also known as a "whistleblower" action, is a lawsuit brought by a private citizen seeking civil penalties or damages against a person or company on behalf of the government for alleged violations of law. If the claims are successful, the person filing the suit may recover a percentage of the damages or penalty from the lawsuit as a reward for exposing a wrongdoing and recovering funds on behalf of the government. This matter was more fully described in the Company's Annual Report on Form 10-K for the year ended December 31, 2012.

On November 5, 2013, the court granted the Company's motion to dismiss and the complaint was dismissed with prejudice. If a motion for reconsideration or an appeal is made, the Company intends to vigorously defend the claims made in this lawsuit. The Company has determined that the likelihood of an adverse outcome is remote, and accordingly, no accrual has been made.

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 Texasseeking a determination that our Excess Policies cover removal of wreck and debris claims arising from Hurricane Ike 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) with only removal of wreck and debris claims. The court consolidated the various suits filed by the underwriters. W&T has not yet filed any claim under such Excess Policies. As of September 30, 2013, we have spent $45.3 million to date and expect to incur an additional $2.1 million of costs for removal of wreck associated with platforms damaged by Hurricane Ike. 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. On July 31, 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 disagree with the Court's ruling and have appealed the decision. Removal of wreck costs are recorded in *Oil and natural gas properties and equipment* on the Balance Sheet. If we are successful in our appeal, any recoveries from claims made on these Excess Policies related to this issue will be recorded as reductions in this line item, which will reduce the Company's DD&A rate.

Royalties. In 2009, the Company recognized $5.3 million in allowable reductions of cash payments for royalties owed to the Office of Natural Resources Revenue (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 the third quarter of 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue of $4.7 million in the third quarter of 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR and we are pursuing our claim to resolve the matter.

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, management believes 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. Recognized expenses related to accrued and settled claims, complaints and fines were $0.3 million for the nine months ended September 30, 2013 and $8.8 million for the nine months ended September 30, 2012. These expenses are reported in *General and administrative expenses* on the statement of income and reflect the items noted above and other various claims and complaints. As of September 30, 2013 and December 31, 2012, we have recorded $0.1 million and $1.3 million, respectively, which are included in *Accrued liabilities* on the balance sheet, for the loss contingencies matters that include the events described above and other minor environmental and litigation matters which we are addressing in the normal course of business.

13. Subsequent Events

2013 Acquisition. On October 17, 2013, W&T entered into a purchase and sale agreement to acquire certain oil and natural gas property interests from Callon Petroleum Operating Company ("Callon"), referred to herein as the "Callon Properties." Pursuant to the purchase and sale agreement, transactions covering the transfer of certain properties that had no preferential rights were consummated on November 5, 2013 (the "First Closing"). The First Closing included the majority of the value of the Callon Properties. A final close is expected to be consummated by the end of November 2013 for properties that have preferential rights which are not exercised. The effective date of the transaction was July 1, 2013. After customary effective date adjustments and closing adjustments, the cash consideration paid was $76.4 million, which is subject to further post-closing adjustments. In addition, we assumed the related ARO, which is set forth in the table below. The acquisition was funded from borrowings under our revolving bank credit facility and cash on hand. The First Closing of the Callon Properties consists 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 these properties are located in the Gulf of Mexico.

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

Oil and natural gas properties and equipment	$	79,136
Asset retirement obligations – current		(15)
Asset retirement obligations – non-current		(2,713)
Total cash paid	$	76,408

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 for the Callon Properties acquisition related to the First Closing.

Revenues, Net Income and Pro Forma Financial Information — Unaudited

The Callon Properties were not included in our consolidated results for the quarter ended September 30, 2013 as the acquisition closing date was subsequent to such date. There were no expenses associated with acquisition activities and transition activities related to the acquisition of the Callon Properties for the nine months ended September 30, 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 unaudited historical condensed consolidated financial statements and Callon Properties' unaudited historical financial statement for the periods presented.

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. If the transaction had been in effect for 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 properties used in the pro forma financial information are from the First Closing and exclude properties with outstanding preferential rights by third parties.

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	2012	2013	2012
Revenues	$ 254,092	$ 197,076	$ 766,801	$ 670,881
Net income	16,513	858	69,310	63,801
Basic and diluted earnings per common share	0.22	0.01	0.91	0.84

For the pro forma financial information, certain information was derived from 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 included in the First Closing (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues (a)	$ 9,537	$ 11,130	$ 27,641	$ 33,536
Direct operating expenses (a)	1,459	1,614	4,915	4,628
Insurance costs (b)	510	510	1,531	1,214
DD&A (c)	3,615	4,822	10,735	13,095
Interest expense (d)	382	382	1,146	1,146
Capitalized interest (e)	4	219	(74)	398
Income tax expense (f)	1,248	1,254	3,286	4,569

The sources of information and significant assumptions are described below:

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

(b) Incremental costs for insurance were estimated from the incremental costs to add theCallon Properties included in the First Close to W&T's insurance programs. The direct operating expenses for the Callon Properties described above exclude insurance costs.

(c) 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 currently existing full cost pool in order to compute such amounts. The purchase price allocation included $7.2 million that was allocated to the pool of unevaluated properties for oil and natural gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties. ARO was estimated by W&T management.

(d) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $76.4 million, which equates to the cash component of the transaction, and an interest rate of 2.0%, 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. Positive amounts represent increases to net expenses. The negative amount represents a decrease to net expenses.

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

(g) The 2012 periods above do not include any pro forma adjustments related to the 2012 acquisition as described in Note 2.

Revolving Bank Credit Facility. On November 8, 2013, the Company entered into the Fifth Amended and Restated Credit Agreement (the "New Credit Agreement"). The New Credit Agreement increased the total credit facility amount from $900.0 million to $1.2 billion and matures on November 8, 2018. The borrowing base was not changed and remains at $800.0 million. The proved reserves associated with the Callon Properties were not considered for purposes of the redetermination of the borrowing base. The New Credit Agreement increased the capacity to issue letters of credit from $100.0 million to $300.0 million. The financial covenant for the maximum leverage ratio of total debt to EBITDA, as defined in the New Credit Agreement, was increased from 3.0 to 1.0 to 3.5 to 1.0. The other financial covenant, the minimum current ratio, as defined in the New Credit Agreement, remains at 1.0 to 1.0. Interest rates, or margins, were decreased for certain categories. These categories are determined by the Company's borrowing base utilization. Interest rates were unchanged for all the other categories. In addition, there were other minor changes from the previous Credit Agreement that were favorable to the Company. All other terms and conditions were substantially the same as under the previous Credit Agreement.

14. Supplemental Guarantor Information

Our payment obligations under the Credit Agreement as of September 30, 2013 were, and our payment obligations under the 8.50% Senior Notes and the New Credit Agreement (see Notes 6 and 13) are, fully and unconditionally guaranteed by certain of our wholly-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 unaudited condensed consolidating financial information presents the financial condition, results of operations and cash flows of W&T Offshore, Inc. (the “Parent Company”) and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company’s results on a consolidated basis.

Condensed Consolidating Balance Sheet as of September 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 15,227	$ —	$ —	$ 15,227
Receivables:				
Oil and natural gas sales	66,953	18,301	(33)	85,221
Joint interest and other	31,492	—	—	31,492
Total receivables	98,445	18,301	(33)	116,713
Restricted cash and cash equivalents	16,459	—	—	16,459
Prepaid expenses and other assets	152,739	3,991	(123,880)	32,850
Total current assets	282,870	22,292	(123,913)	181,249
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,703,175	416,911	—	7,120,086
Furniture, fixtures and other	21,325	—	—	21,325
Total property and equipment	6,724,500	416,911	—	7,141,411
Less accumulated depreciation, depletion and amortization	4,690,550	260,218	—	4,950,768
Net property and equipment	2,033,950	156,693	—	2,190,643
Restricted deposits for asset retirement obligations	34,966	—	—	34,966
Deferred income taxes	—	4,549	(4,549)	—
Other assets	481,029	441,908	(906,095)	16,842
Total assets	$ 2,832,815	$ 625,442	$ (1,034,557)	$ 2,423,700
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 130,021	$ —	$ (33)	$ 129,988
Undistributed oil and natural gas proceeds	40,989	289	—	41,278
Asset retirement obligations	95,014	—	—	95,014
Accrued liabilities	45,272	129,656	(123,880)	51,048
Total current liabilities	311,296	129,945	(123,913)	317,328
Long-term debt	1,052,984	—	—	1,052,984
Asset retirement obligations, less current portion	235,782	31,311	—	267,093
Deferred income taxes	181,953	—	(4,549)	177,404
Other liabilities	457,768	—	(441,909)	15,859
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	404,604	231,759	(231,759)	404,604
Retained earnings	212,594	232,427	(232,427)	212,594
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	593,032	464,186	(464,186)	593,032
Total liabilities and shareholders' equity	$ 2,832,815	$ 625,442	$ (1,034,557)	$ 2,423,700

Condensed Consolidating Balance Sheet as of December 31, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 12,245	$ —	$ —	$ 12,245
Receivables:				
Oil and natural gas sales	80,729	17,004	—	97,733
Joint interest and other	56,439	—	—	56,439
Income taxes	163,750	—	(115,866)	47,884
Total receivables	300,918	17,004	(115,866)	202,056
Prepaid expenses and other assets	25,822	—	—	25,822
Total current assets	338,985	17,004	(115,866)	240,123
Property and equipment – at cost:				
Oil and natural gas properties and equipment	6,356,529	337,981	—	6,694,510
Furniture, fixtures and other	21,786	—	—	21,786
Total property and equipment	6,378,315	337,981	—	6,716,296
Less accumulated depreciation, depletion and amortization	4,461,886	193,955	—	4,655,841
Net property and equipment	1,916,429	144,026	—	2,060,455
Restricted deposits for asset retirement obligations	28,466	—	—	28,466
Deferred income taxes	—	13,509	(13,509)	—
Other assets	442,540	393,499	(816,096)	19,943
Total assets	$ 2,726,420	$ 568,038	$ (945,471)	$ 2,348,987
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 123,792	$ 93	$ —	$ 123,885
Undistributed oil and natural gas proceeds	36,791	282	—	37,073
Asset retirement obligations	92,595	—	35	92,630
Accrued liabilities	20,755	116,132	(115,866)	21,021
Total current liabilities	273,933	116,507	(115,831)	274,609
Long-term debt	1,087,611	—	—	1,087,611
Asset retirement obligations, less current portion	262,524	28,934	(35)	291,423
Deferred income taxes	158,758	—	(13,509)	145,249
Other liabilities	402,407	—	(393,499)	8,908
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	396,186	231,759	(231,759)	396,186
Retained earnings	169,167	190,838	(190,838)	169,167
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	541,187	422,597	(422,597)	541,187
Total liabilities and shareholders' equity	$ 2,726,420	$ 568,038	$ (945,471)	$ 2,348,987

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	$ 195,064	$ 49,491	$ —	$ 244,555
Operating costs and expenses:				
Lease operating expenses	64,952	2,394	—	67,346
Production taxes	1,807	—	—	1,807
Gathering and transportation	2,706	905	—	3,611
Depreciation, depletion, amortization and accretion	80,230	23,913	—	104,143
General and administrative expenses	19,375	649	—	20,024
Derivative loss	15,659	—	—	15,659
Total costs and expenses	184,729	27,861	—	212,590
Operating income	10,335	21,630	—	31,965
Earnings of affiliates	14,032	—	(14,032)	—
Interest expense:				
Incurred	21,373	—	—	21,373
Capitalized	(2,573)	—	—	(2,573)
Other income	9,062	—	—	9,062
Income before income tax expense	14,629	21,630	(14,032)	22,227
Income tax expense	435	7,598	—	8,033
Net income	$ 14,194	$ 14,032	$ (14,032)	$ 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	$ 590,492	$ 148,668	$ —	$ 739,160
Operating costs and expenses:				
Lease operating expenses	184,458	10,477	—	194,935
Production taxes	5,375	—	—	5,375
Gathering and transportation	10,099	2,564	—	12,663
Depreciation, depletion, amortization and accretion	244,597	68,314	—	312,911
General and administrative expenses	57,738	3,241	—	60,979
Derivative loss	6,186	—	—	6,186
Total costs and expenses	508,453	84,596	—	593,049
Operating income	82,039	64,072	—	146,111
Earnings of affiliates	41,589	—	(41,589)	—
Interest expense:				
Incurred	64,157	—	—	64,157
Capitalized	(7,537)	—	—	(7,537)
Other income	9,075	—	—	9,075
Income before income tax expense	76,083	64,072	(41,589)	98,566
Income tax expense	12,875	22,483	—	35,358
Net income	$ 63,208	$ 41,589	$ (41,589)	$ 63,208

Condensed Consolidating Statement of Income for the Three Months Ended September 30, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 141,139	$ 44,807	$ —	$ 185,946
Operating costs and expenses:				
Lease operating expenses	47,353	6,058	—	53,411
Production taxes	1,353	—	—	1,353
Gathering and transportation	2,084	726	—	2,810
Depreciation, depletion, amortization and accretion	58,744	18,718	—	77,462
General and administrative expenses	18,691	—	—	18,691
Derivative loss	24,659	—	—	24,659
Total costs and expenses	152,884	25,502	—	178,386
Operating income (loss)	(11,745)	19,305	—	7,560
Earnings of affiliates	12,551	—	(12,551)	—
Interest expense:				
Incurred	14,791	—	—	14,791
Capitalized	(3,383)	—	—	(3,383)
Other income	202	—	—	202
Income (loss) before income tax expense	(10,400)	19,305	(12,551)	(3,646)
Income tax expense (benefit)	(8,929)	6,754	—	(2,175)
Net income (loss)	$ (1,471)	$ 12,551	$ (12,551)	$ (1,471)

Condensed Consolidating Statement of Income for the Nine Months Ended September 30, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Revenues	$ 473,297	$ 164,048	$ —	$ 637,345
Operating costs and expenses:				
Lease operating expenses	150,860	19,489	—	170,349
Production taxes	4,174	—	—	4,174
Gathering and transportation	8,788	2,352	—	11,140
Depreciation, depletion, amortization and accretion	189,827	62,067	—	251,894
General and administrative expenses	60,200	2,593	—	62,793
Derivative loss	14,421	—	—	14,421
Total costs and expenses	428,270	86,501	—	514,771
Operating income	45,027	77,547	—	122,574
Earnings of affiliates	50,395	—	(50,395)	—
Interest expense:				
Incurred	43,409	—	—	43,409
Capitalized	(9,899)	—	—	(9,899)
Other income	210	—	—	210
Income before income tax expense	62,122	77,547	(50,395)	89,274
Income tax expense	6,807	27,152	—	33,959
Net income	$ 55,315	$ 50,395	$ (50,395)	$ 55,315

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	$ 41,589	$ (41,589)	$ 63,208
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	244,597	68,314	—	312,911
Amortization of debt issuance costs and premium	1,366	—	—	1,366
Share-based compensation	8,457	—	—	8,457
Derivative loss	6,186	—	—	6,186
Cash payments on derivative settlements	(6,855)	—	—	(6,855)
Deferred income taxes	22,621	8,960	—	31,581
Earnings of affiliates	(41,589)	—	41,589	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	13,775	(1,264)	—	12,511
Joint interest and other receivables	24,947	—	—	24,947
Insurance receivables	5,117	—	—	5,117
Income taxes	39,909	13,524	—	53,433
Prepaid expenses and other assets	(6,823)	(52,400)	48,408	(10,815)
Asset retirement obligation settlements	(59,017)	(171)	—	(59,188)
Accounts payable, accrued liabilities and other	81,501	(119)	(48,408)	32,974
Net cash provided by operating activities	397,400	78,433	—	475,833
Investing activities:				
Investment in oil and natural gas properties and equipment	(344,659)	(78,433)	—	(423,092)
Proceeds from sales of assets and other, net	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	(341,434)	(78,433)	—	(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)
Debt issuance costs	(164)	—	—	(164)
Dividends to shareholders	(19,570)	—	—	(19,570)
Other	(250)	—	—	(250)
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

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2012

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 55,315	50,395	(50,395)	$ 55,315
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	189,827	62,067	—	251,894
Amortization of debt issuance costs	2,046	—	—	2,046
Share-based compensation	9,137	—	—	9,137
Derivative loss	14,421	—	—	14,421
Cash payments on derivative settlements	(6,960)	—	—	(6,960)
Deferred income taxes	42,816	1,649	—	44,465
Earnings of affiliates	(50,395)	—	50,395	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	24,162	6,158	—	30,320
Joint interest and other receivables	3,935	—	—	3,935
Insurance receivables	500	—	—	500
Income taxes	(49,830)	25,503	—	(24,327)
Prepaid expenses and other assets	669	(101,473)	101,474	670
Asset retirement obligations	(63,150)	—	—	(63,150)
Accounts payable, accrued liabilities and other	136,449	(1,752)	(101,474)	33,223
Net cash provided by operating activities	308,942	42,547	—	351,489
Investing activities:				
Investment in oil and natural gas properties and equipment	(269,825)	(42,547)	—	(312,372)
Proceeds from sales of oil and gas properties and equipment	30,453	—	—	30,453
Change in restricted cash	(24,026)	—	—	(24,026)
Deposit for acquisition	(22,800)	—	—	(22,800)
Purchases of furniture, fixtures and other	(2,125)	—	—	(2,125)
Net cash used in investing activities	(288,323)	(42,547)	—	(330,870)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	316,000	—	—	316,000
Repayments of long-term debt – revolving bank credit facility	(314,000)	—	—	(314,000)
Debt issuance costs	(2,081)	—	—	(2,081)
Dividends to shareholders	(17,848)	—	—	(17,848)
Other	(209)	—	—	(209)
Net cash used in financing activities	(18,138)	—	—	(18,138)
Increase in cash and cash equivalents	2,481	—	—	2,481
Cash and cash equivalents, beginning of period	4,512	—	—	4,512
Cash and cash equivalents, end of period	$ 6,993	—	—	$ 6,993

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, 2012 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.

Overview

We are an independent oil and natural gas producer with operations offshore in the Gulf of Mexico and onshore in both the Permian Basin of West Texas and in East Texas. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 67 producing offshore fields in federal and state waters (60 producing and seven fields capable of producing). We currently have under lease approximately 1.3 million gross acres, including approximately 0.6 million gross acres on the Gulf of Mexico Shelf, approximately 0.5 million gross acres in the deepwater and approximately 0.2 million gross acres onshore in Texas. A substantial majority of our daily production is derived from wells we operate offshore. 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 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, 2013 were comprised of approximately 40.7% oil and condensate, 11.9% NGLs and 47.4% 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 thousand cubic feet equivalent ("Mcfe") for oil, NGLs and natural gas may differ significantly. In the nine months ended September 30, 2013, revenues from the sale of oil and NGLs made up 81.3% of our total revenues compared to 82.6% in the same period of 2012 with the decrease attributable to higher natural gas prices during the 2013 period. For the nine months ended September 30, 2013, our combined total production of oil, condensate, NGLs and natural gas was approximately 1.6% higher on a Mcfe basis than during the same period in 2012, and our total revenues were 16.0% higher in the nine months ended September 30, 2013, driven primarily by higher oil production and higher natural gas prices. See section *Results of Operations—Nine months Ended September 30, 2013 Compared to the Nine Months Ended September 30, 2012* for additional information on our revenues and production.

In October 2012, we acquired from Newfield certain oil and gas leasehold interests in the Gulf of Mexico. The operating results of the Newfield Properties are included in our results of operations and income statement for the period ended September 30, 2013. The results for the period ended September 30, 2012 do not include the Newfield Properties' operations as this period precedes the acquisition date.

During the nine months ended September 30, 2013, our average realized oil sales price continued at historically high levels, but were slightly lower than those realized in the same period of 2012. Two comparable oil price benchmarks are the unweighted average daily posted spot price of WTI crude oil, which increased 2.1% from the comparable period, and the unweighted average daily posted spot price of Brent crude oil, which decreased 3.4% from the comparable period. 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 plus a premium depending on the type of crude oil. Most of our oil production is from offshore Gulf of Mexico, which is comprised of various crudes including Light Louisiana Sweet, Heavy Louisiana Sweet, Poseidon and others. Starting in the first quarter of 2011 and continuing through September 2013, these various crudes sold at a premium, and sometimes a significant premium, relative to WTI. During the nine months ended September 30, 2013, premiums for Light Louisiana Sweet crude and Heavy Louisiana Sweet crude ranged between $4.00 and $22.00 per barrel higher than WTI, with premiums from July 2013 to September 2013 being in the low end of the range at $4.00 to $9.00 per barrel as the price of WTI increased relative to Brent. During the nine months ended September 30, 2012, premiums for Light Louisiana Sweet crude and Heavy Louisiana Sweet crude ranged between $10.00 and $22.00 per barrel. The average premium spread prior to 2011 was approximately $2.00 to $3.00 per barrel. Our offshore oil production competes with foreign-sourced crude oil, which is priced primarily based on the spot price of Brent.

The infrastructure to move crude oil within the United States has seen a major change over the past few years. 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). 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, which in turn allowed WTI pricing to increase relative to Brent. Not only is pipeline capacity increasing, but rail receiving capacity on the East Coast has expanded considerably and is expected to continue to increase. Rail receiving capacity on the Gulf Coast is also expanding, but not at the same rate as the East Coast, as mostly pipeline capacity is being added to serve that market. The expanded infrastructure to deliver crude oil to domestic refineries by pipelines and rail has put market pressure to contract the spread of Brent to WTI, as the price of Brent has decreased and the price of WTI has increased in 2013 as compared to 2012. The spread between Brent and WTI widened more recently due to crude oil inventory increases in the U.S. due to both increased imports and increased domestic production. Spreads are expected to remain volatile, but absolute levels could continue to be more narrow due to the reasons enumerated above.

Oil prices are affected by world events, such as political unrest in the Middle East, the threat of hostilities, demand changes in various countries and world economic growth. Thus, crude oil prices will likely continue to be volatile. For the nine months ended September 30, 2013, WTI crude oil prices ranged from $87.00 to $111.00 per barrel and Brent crude oil prices ranged from $97.00 to $119.00 per barrel. The U.S. Energy Information Administration ("EIA") estimates that the average WTI crude spot price was $94.00 per barrel in 2012 and will be $99.00 per barrel in 2013 and $96.00 per barrel in 2014. EIA estimates the average Brent crude oil spot price was $112.00 per barrel in 2012 and projects the average price to be $108.00 per barrel and $102.00 per barrel in 2013 and 2014, respectively. EIA expects world-wide supply and consumption for oil and liquids fuels to be fairly equal for 2013 and 2014, resulting in minor inventory withdrawals or builds.

Our average realized NGLs sale prices decreased 18.8% during the nine months ended September 30, 2013 compared to the same period of 2012. According to industry sources, increased domestic NGLs production has been the primary factor affecting price realizations. During the nine months ended September 30, 2013, prices for domestic ethane and propane, two common NGL components, decreased 33% and 10%, respectively, from the comparable period in 2012 and other domestic NGLs prices decreased between 0% and 21%. As long as ethane and propane inventories continue to be high and NGLs production continues to be high, we would expect prices for NGLs to be weak. In addition, as long as the crude to natural gas price ratio 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 and to some extent propane. Many natural gas processing facilities are re-injecting ethane back into the natural gas stream after processing due to excess ethane supplies. This in turn has increased natural gas supplies and negatively impacted natural gas pricing.

Prices for natural gas in the U.S. have improved during the nine months ended September 30, 2013 compared to the prior period largely due to above-average storage withdrawals in response to the colder winter weather, lower net imports from Canada and higher industrial 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 and domestic economic conditions, and they have historically been subject to substantial fluctuation. During the nine months ended September 30, 2013, the average realized sales price for our natural gas production increased 37.5% from the comparable period in 2012 to $3.74 per Mcf. A comparable benchmark is the Henry Hub unweighted average daily posted spot price, which increased 45.3% from the comparable period. Although the price has increased significantly on a percentage basis, the price 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 storage levels building during the injection season, (iii) natural gas continuing to be produced as a by-product in conjunction with the high level of oil drilling, (iv) increasing availability of liquefied natural gas, (v) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling and production techniques and (vi) 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 2013 injection season (end of October 2013) is expected to be about 3% below the record high level of last year levels of 3,929 billion cubic feet. EIA expects the Henry Hub natural gas spot price, which averaged $2.75 per British thermal unit (MMBtu) in 2012, will average $3.68 per MMBtu in 2013 and $3.91 per MMBtu in 2014. EIA projects U.S. supply to be higher than consumption for both 2013 and 2014. According to Baker Hughes, the U.S. natural gas rig count decreased from 809 rigs at the beginning of 2012 to 437 by the end of September of 2012. The natural gas rig count continued to decline for the remainder of 2012 and started the year 2013 at 431 rigs. The rig count continued to decrease further and by the end of September 2013, the rig count had decreased to 378 rigs. 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 enumerated above. EIA projects the percentage of electricity fueled by natural gas to be 27.4% in 2013 compared to 30.4% in 2012, and to further decline to 26.7% in 2014 based on the relative 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 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.

Should prices decline for oil, NGLs and natural gas in the future, it would negatively impact our future oil, NGLs and natural gas revenues, earnings and liquidity, and could result in ceiling test write-downs of the carrying value of our oil and natural gas properties, reductions in proved reserves, issues with financial ratio compliance, and a reduction of the borrowing base associated with our Credit Agreement, depending on the severity of such declines. If any of these events were to occur and were significant, it may limit the willingness of financial institutions and investors to provide capital to us and others in the oil and natural gas industry.

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, (1)				Nine Months Ended September 30, (1)			
	2013	2012	Change	%	2013	2012	Change	%
	(In thousands, except percentages and per share data)							
Financial:								
Revenues:								
Oil	$ 184,087	$ 138,034	$ 46,053	33.4%	$ 550,329	$ 461,846	$ 88,483	19.2%
NGLs	16,505	12,468	4,037	32.4%	50,631	64,793	(14,162)	(21.9)%
Natural gas	43,588	35,054	8,534	24.3%	136,520	109,174	27,346	25.0%
Other	375	390	(15)	(3.8)%	1,680	1,532	148	9.7%
Total revenues	244,555	185,946	58,609	31.5%	739,160	637,345	101,815	16.0%
Operating costs and expenses:								
Lease operating expenses	67,346	53,411	13,935	26.1%	194,935	170,349	24,586	14.4%
Production taxes	1,807	1,353	454	33.6%	5,375	4,174	1,201	28.8%
Gathering and transportation	3,611	2,810	801	28.5%	12,663	11,140	1,523	13.7%
Depreciation, depletion, amortization and accretion	104,143	77,462	26,681	34.4%	312,911	251,894	61,017	24.2%
General and administrative expenses	20,024	18,691	1,333	7.1%	60,979	62,793	(1,814)	(2.9)%
Derivative loss	15,659	24,659	(9,000)	(36.5)%	6,186	14,421	(8,235)	(57.1)%
Total costs and expenses	212,590	178,386	34,204	19.2%	593,049	514,771	78,278	15.2%
Operating income	31,965	7,560	24,405	322.8%	146,111	122,574	23,537	19.2%
Interest expense, net of amounts capitalized	18,800	11,408	7,392	64.8%	56,620	33,510	23,110	69.0%
Other income	9,062	202	8,860	N/A	9,075	210	8,865	N/A
Income (loss) before income tax expense	22,227	(3,646)	25,873	N/A	98,566	89,274	9,292	10.4 %
Income tax expense (benefit)	8,033	(2,175)	10,208	N/A	35,358	33,959	1,399	4.1%
Net income (loss)	$ 14,194	$ (1,471)	$ 15,665	N/A	$ 63,208	$ 55,315	$ 7,893	14.3%
Basic and diluted earnings (loss) per common share	$ 0.19	$ (0.02)	$ 0.21	N/A	$ 0.83	$ 0.73	$ 0.10	13.7%

(1) In the fourth quarter of 2012, we acquired the Newfield Properties.

N/A = percentage change not applicable

	Three Months Ended September 30, (1)				Nine Months Ended September 30, (1)			
	2013	2012	Change	%	2013	2012	Change	%
Operating:								
Net sales volumes:								
Oil (MBbls)	1,725	1,371	354	25.8%	5,226	4,361	865	19.8%
NGLs (MBbls)	494	451	43	9.5%	1,520	1,581	(61)	(3.9)%
Natural gas (MMcf)	11,924	11,401	523	4.6%	36,486	40,097	(3,611)	(9.0)%
Total natural gas and oil (MBoe) (2)	4,207	3,722	485	13.0%	12,828	12,625	203	1.6%
Total natural gas and oil (MMcfe) (2)	25,241	22,331	2,910	13.0%	76,967	75,749	1,218	1.6%
Average daily equivalent sales (Boe/d) (2)	45,727	40,454	5,273	13.0%	46,989	46,076	913	2.0%
Average daily equivalent sales (Mcfe/d) (2)	274,364	242,723	31,641	13.0%	281,932	276,455	5,477	2.0%
Average realized sales prices:								
Oil ($/Bbl)	$ 106.70	$ 100.68	$ 6.02	6.0%	$ 105.30	$ 105.89	$ (0.59)	(0.6)%
NGLs ($/Bbl)	33.39	27.66	5.73	20.7%	33.30	40.99	(7.69)	(18.8)%
Natural gas ($/Mcf)	3.66	3.07	0.59	19.2%	3.74	2.72	1.02	37.5%
Oil equivalent ($/Boe) (2)	58.04	49.86	8.18	16.4%	57.49	50.36	7.13	14.2%
Natural gas equivalent ($/Mcfe) (2)	9.67	8.31	1.36	16.4%	9.58	8.39	1.19	14.2%
Average per Mcfe ($/Mcfe) (2):								
Lease operating expenses	$ 2.67	$ 2.39	$ 0.28	11.7%	$ 2.53	$ 2.25	$ 0.28	12.4%
Gathering and transportation	0.14	0.13	0.01	7.7%	0.16	0.15	0.01	6.7%
Production costs	2.81	2.52	0.29	11.5%	2.69	2.40	0.29	12.1%
Production taxes	0.07	0.06	0.01	16.7%	0.07	0.06	0.01	16.7%
Depreciation, depletion, amortization and accretion	4.13	3.47	0.66	19.0%	4.07	3.33	0.74	22.2%
General and administrative expenses	0.79	0.84	(0.05)	(6.0)%	0.79	0.83	(0.04)	(4.8)%
	$ 7.80	$ 6.89	$ 0.91	13.2%	$ 7.62	$ 6.62	$ 1.00	15.1%
Total number of wells drilled (gross):								
Offshore	3	1	2	200.0%	6	3	3	100.0
Onshore	10	18	(8)	(44.4)%	33	55	(22)	(40.0)%
Total number of productive wells drilled (gross):								
Offshore	3	1	2	200.0%	5	3	2	66.7%
Onshore	10	18	(8)	(44.4)%	33	55	(22)	(40.0)%

(1) In the fourth quarter of 2012, we acquired the Newfield Properties.

(2) The conversion 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
MMcf - million cubic feet
MMcfe - million cubic feet equivalent
Mcfe/d - thousand cubic feet equivalent per day

N/A = percentage change not applicable

Three Months Ended September 30, 2013 Compared to the Three Months Ended September 30, 2012

Revenues. Total revenues increased $58.6 million to $244.6 million for the third quarter of 2013 as compared to the same period in 2012. Oil revenues increased $46.1 million, NGLs revenues increased $4.0 million, natural gas revenues increased $8.5 million and other revenues were flat. The oil revenue increase was attributable to a 25.8% increase in sales volumes and a 6.0% increase in the average realized sales price to $106.70 per barrel for the third quarter of 2013 from $100.68 per barrel for the prior year period. The NGLs revenue increase was attributable to a 20.7% increase in the average realized sales price to $33.39 per barrel for the third quarter of 2013 from $27.66 per barrel for the prior year period and an increase of 9.5% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 19.2% increase in the average realized natural gas sales price to $3.66 per Mcf in the third quarter of 2013 from $3.07 per Mcf for the prior year period and a 4.6% increase in sales volumes from the comparable period. Production for all commodities was positively impacted by production at Ship Shoal 349, onshore properties in West Texas and the Newfield Properties acquired in 2012. Production was negatively impacted for all commodities from natural production declines and from production deferrals affecting various fields in the third quarter of 2013. The production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 4.7 Bcfe during the third quarter of 2013. Specifically, production at Mississippi Canyon 506 "Wrigley" continues to be deferred as a result of maintenance at Shell's Cognac platform and related pipelines. Also, production was deferred at our Fairway field due to well and maintenance issues and a turnaround at our Yellowhammer plant. During the third quarter of 2012, we experienced production deferrals primarily due to Hurricane Isaac and various pipeline outages.

Revenues from oil and liquids as a percent of our total revenues were 82.0% for the third quarter of 2013 compared to 80.9% for the prior year period. NGLs realized sales prices as a percent of oil realized prices increased to 31.3% for the third quarter of 2013 compared to 27.5% for the comparable period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, increased $13.9 million to $67.3 million in the third quarter of 2013 compared to the prior year period. On a per Mcfe basis, lease operating expenses increased to $2.67 per Mcfe during the third quarter 2013 compared to $2.39 per Mcfe during the comparable 2012 period. On a component basis, base lease operating expenses increased by $8.9 million primarily attributable to the Newfield Properties, expanding onshore operations, ad valorem tax refunds and other adjustments that occurred in the 2012 period that did not reoccur in the 2013 period, partially offset by increased processing fees charged to third-parties. Workover expense increased $3.7 million primarily as a result of expanded onshore operations and work on the A-12 well at our Ship Shoal 349 field. Facilities maintenance increased by $2.7 million which was primarily attributable to a shutdown for scheduled maintenance at our Yellowhammer plant. Partially offsetting these increases was a decrease of $1.5 million in insurance premiums.

Production taxes. Production taxes increased $0.5 million to $1.8 million in the third quarter of 2013 compared to the prior year period primarily due to onshore activities and are currently not a large component of our operating costs. Most of our production is from federal waters where no production taxes are imposed, whereas onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.8 million to $3.6 million for the third quarter of 2013 compared to the prior year period primarily due to escalation in third-party transportation fees and increased production.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $4.13 per Mcfe for the third quarter of 2013 from $3.47 per Mcfe in the prior year period. On a nominal basis, DD&A increased to $104.1 million for the third quarter of 2013 from $77.5 million in the prior year period. DD&A on a per Mcfe basis and nominal basis increased primarily due to costs capitalized to the full cost pool from the unevaluated pool and from increases in our ARO estimates without a corresponding increase in proved reserves, which primarily occurred in the latter part of 2012. In addition, we incurred significant development costs during 2012 and during the first half of 2013 above previous estimates, and revised upward our estimates of future development costs. The Newfield Properties also increased the DD&A rate on a per Mcfe basis.

General and administrative expenses. G&A increased to $20.0 million for the third quarter of 2013 from $18.7 million for the prior year period primarily due to increases in contract labor, professional fees and surety bond fees, partially offset by increased overhead billings to joint interest partners and lower compensation-related expenses. G&A on a per Mcfe basis was $0.79 per Mcfe for the third quarter of 2013, compared to $0.84 per Mcfe for the prior year period.

Derivative loss. For the third quarter of 2013 and 2012, our derivative positions resulted in net losses of $15.7 million and $24.7 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 contracts relate to production for the current year and next year, changes in the fair value for all open contracts are recorded currently. For the third quarter of 2013, the net loss was comprised of a $4.5 million realized loss and an $11.2 million unrealized loss. For the third quarter of 2012, the net loss consisted of a realized loss of $0.9 million and an unrealized loss of $23.8 million. For additional information about our derivatives, refer to Item 1 *Financial Statements – Note 5 – Derivative Financial Instruments.*

Interest expense. Interest expense incurred increased to $21.4 million for the third quarter of 2013 from $14.8 million for the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in the third quarter of 2013 compared to $600.0 million in the prior year period due to the issuance of 8.50% Senior Notes during October 2012. During the third quarter of 2013 and 2012, $2.6 million and $3.4 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 2012.

Other income. During the third quarter of 2013, other income was $9.1 million and consisted primarily of $9.2 million received in conjunction with a payment to W&T for an option exercised by a counterparty. During the third quarter of 2012, other income was $0.2 million.

Income tax expense (benefit). Income tax expense was $8.0 million for the third quarter of 2013 compared to an income tax benefit of $2.2 million for the same period of 2012 primarily attributable to changes in pre-tax income. 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. Our effective tax rate for the third quarter of 2012 was 59.7% and differed from the federal statutory rate of 35.0% primarily as a result of changes in the full year forecasted effective tax rate. The effective tax rate for the third quarter of 2012 was not representative of the full year effective tax rate.

Nine Months Ended September 30, 2013 Compared to the Nine Months Ended September 30, 2012

Revenues. Total revenues increased $101.8 million to $739.2 million for the nine months ended September 30, 2013 as compared to the same period in 2012. Oil revenues increased $88.5 million, NGLs revenues decreased $14.2 million, natural gas revenues increased $27.3 million and other revenues increased $0.2 million. The oil revenue increase was attributable to a 19.8% increase in sales volumes, partially offset by a 0.6% decrease in the average realized sales price to $105.30 per barrel for the nine months ended September 30, 2013 from $105.89 per barrel for the prior year period. The NGLs revenue decrease was attributable to an 18.8% decrease in the average realized sales price to $33.30 per barrel for the nine months ended September 30, 2013 from $40.99 per barrel for the prior year period and a decrease of 3.9% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 37.5% increase in the average realized natural gas sales price to $3.74 per Mcf for the nine months ended September 30, 2013 from $2.72 per Mcf for the prior year period and was partially offset by a 9.0% decrease in sales volumes from the comparable period. Production for all commodities was positively impacted by production at Ship Shoal 349, onshore properties in West Texas and the Newfield Properties acquired in 2012. Production was negatively impacted for all commodities from natural production declines and from production deferrals affecting various fields for the nine months ended September 30, 2013. The production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 9.3 Bcfe during the nine months ended September 30, 2013. Specifically, production at Mississippi Canyon 506 "Wrigley" has been deferred for all of the nine months ended September 20, 2013 as a result of maintenance at Shell's Cognac platform and related pipelines. Production was deferred at our Fairway field in the second and third quarters of 2013 due to well and maintenance issues and a turnaround at our Yellowhammer plant. During the nine months ended September 30, 2012, we experienced production deferrals due to Hurricane Isaac and various pipeline outages.

Revenues from oil and liquids as a percent of our total revenues were 81.3% for the nine months ended September 30, 2013 compared to 82.6% for the prior year period. NGLs realized sales prices as a percent of oil realized prices decreased to 31.6% for the nine months ended September 30, 2013 compared to 38.7% for the comparable period.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, increased $24.6 million to $194.9 million for the nine months ended September 30, 2013 compared to the prior year period. On a per Mcfe basis, lease operating expenses increased to $2.53 per Mcfe for the nine months ended September 30, 2013 compared to $2.25 per Mcfe for the comparable 2012 period. On a component basis, workover expense increased $13.7 million primarily as a result of a rig workover on a well at our Main Pass 69 field. Base lease operating expenses increased $8.4 million primarily attributable to the Newfield Properties, expanded onshore operations, ad valorem tax refunds received in 2012 and other adjustments that occurred in the 2012 period that did not reoccur in the 2013 period, partially offset by increased processing fees charged to third-parties. Facilities maintenance expense increased $4.5 million which was primarily attributable to a shutdown for scheduled maintenance at our Yellowhammer plant. Partially offsetting these increases was a decrease of $2.3 million in insurance premiums.

Production taxes. Production taxes increased $1.2 million to $5.4 million for the nine months ended September 30, 2013 compared to $4.2 million in the prior year period primarily due to onshore activities and are currently not a large component of our operating costs. Most of our production is from federal waters where no production taxes are imposed, whereas onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $1.5 million to $12.7 million for the nine months ended September 30, 2013 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 $4.07 per Mcfe for the nine months ended September 30, 2013 from $3.33 per Mcfe in the prior year period. On a nominal basis, DD&A increased to $312.9 million for the nine months ended September 30, 2013 from $251.9 million in the prior year period. DD&A on a per Mcfe basis and nominal basis increased primarily due to costs capitalized to the full cost pool from both the unevaluated pool and from increases in our ARO estimates without a corresponding increase in proved reserves, which primarily occurred in the latter part of 2012. In addition, we incurred significant development costs during 2012 and during the first half of 2013 above previous estimates, and revised upward our estimates of future development costs. The Newfield Properties also increased the DD&A rate on a per Mcfe basis.

General and administrative expenses. G&A decreased to $61.0 million for the nine months ended September 30, 2013 from $62.8 million for the prior year period primarily due to lower litigation and settlement cost, partially offset by increases in accrued incentive compensation expense, consulting services related to drilling operations and professional services. G&A on a per Mcfe basis was $0.79 per Mcfe for the nine months ended September 30, 2013 compared to $0.83 per Mcfe for the prior year period.

Derivative loss. For the nine months ended September 30, 2013 and 2012, our derivative positions resulted in net losses of $6.2 million and $14.4 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 contracts relate to production for the current year and next year, changes in the fair value for all open contracts are recorded currently. For the nine months ended September 30, 2013, the net loss was comprised of a $6.9 million realized loss and a $0.7 million unrealized gain. For the nine months ended September 30, 2012, the net loss was comprised of a $7.0 million realized loss and a $7.4 million unrealized loss. For additional information about our derivatives, refer to Item 1 *Financial Statements – Note 5 – Derivative Financial Instruments.*

Interest expense. Interest expense incurred increased to $64.2 million for the nine months ended September 30, 2013 from $43.4 million for the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million during the nine months ended September 30, 2013 compared to $600.0 million in the prior year period due to the issuance of 8.50% Senior Notes during October 2012. During the nine months ended September 30, 2013 and 2012, $7.5 million and $9.9 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying unevaluated properties to the full cost pool during the fourth quarter of 2012.

Other income. For the nine months ended September 30, 2013, other income was $9.1 million and consisted primarily of $9.2 million received in conjunction with a payment to W&T for an option exercised by a counterparty. For the nine months ended September 30, 2012, other income was $0.2 million.

Income tax expense. Income tax expense increased to $35.4 million for the nine months ended September 30, 2013 compared to $34.0 million for the prior year period of 2012 primarily attributable to changes in pre-tax income and partially offset by a decrease in our effective tax rate. Our effective tax rate for the nine months ended September 30, 2013 was 35.9% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes. Our effective tax rate for the nine months ended September 30, 2012 was 38.0% and differed from the federal statutory rate of 35.0% primarily as a result of the recapture of deductions for qualified domestic production activities under Section 199 of the IRC as a result of loss carrybacks to prior years.

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, 2013 was $475.8 million compared to $351.5 million for the nine months ended September 30, 2012. The change was primarily due to higher revenues associated with increased production volumes for oil, increased realized prices for natural gas, receipt of income tax refunds, lower income tax payments and collections on joint interest receivables, partially offset by higher lease operating expense and interest expense. Our combined average realized sales price per Mcfe was 14.2% higher than the comparable 2012 period due to oil increasing from 35% to 41% of our combined production and higher natural gas prices. Our combined production of oil, NGLs and natural gas on a Mcfe basis during the nine months ended September 30, 2013 increased 1.6% from the comparable period of 2012.

Net cash used in investing activities during the nine months ended September 30, 2013 and 2012 was $419.9 million and $330.9 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. The increase is primarily attributable to an increase in offshore drilling activity, and partially offset by decreases in onshore drilling activity. There were no acquisitions completed in either period, but during the nine months ended September 30, 2012, there was a deposit of $22.8 million related to the Newfield acquisition which was consummated during the fourth quarter of 2012.

Net cash used in financing activities was $53.0 million and $18.1 million during the nine months ended September 30, 2013 and 2012, respectively. The net cash used during the nine months ended September 30, 2013 was primarily attributable to net repayments of borrowings on our revolving bank credit facility of $33.0 million and dividend payments of $19.6 million. The net cash used in the nine months ended September 30, 2012 was primarily attributable to dividend payments.

At September 30, 2013, we had a cash balance of $15.2 million and $662.9 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $800.0 million as of September 30, 2013.

Credit Agreement and long-term debt. At September 30, 2013 and December 31, 2012, $137.0 million and $170.0 million, respectively, were outstanding under our revolving bank credit facility. During the nine months ended September 30, 2013, the outstanding borrowings on our revolving bank credit facility ranged from $137.0 million to $218.0 million. At September 30, 2013 and December 31, 2012, $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 *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 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, 2013.

During November 2013, we entered into the New Credit Agreement, which replaces the previous Credit Agreement and contains similar terms and conditions except for these primary items: (i) the revolving bank credit facility amount was increased from $900.0 million to $1.2 billion, (ii) the maturity date is November 8, 2018 compared to May 5, 2015, (iii) one financial covenant concerning the maximum leverage ratio of total debt to EBITDA, as defined in the New Credit Agreement, was increased from 3.0 to 1.0 to 3.5 to 1.0, and (iv) interest rates were decreased for certain borrowings depending on our facility utilization ratio. The borrowing base of $800.0 million was reaffirmed as part of the New Credit Agreement. The proved reserves associated with the Callon Properties were not considered for purposes of the redetermination of the borrowing base. For additional information about our New Credit Agreement, refer to *Financial Statements – Note 13 – Subsequent Events* under Part I, Item 1 of this Form 10-Q.

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, 2013, our derivative instruments outstanding consisted of oil contracts relating to approximately 0.8 million barrels ("MMBbls") and 2.1 MMBbls of our anticipated production for the balance of 2013 and for 2014, respectively. See *Financial Statements – Note 5– Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q for additional information.

Hurricane Remediation, Insurance Claims and Insurance. During the third quarter of 2008, Hurricane Ike caused substantial property damage and we continue to incur costs and submit claims to our insurance underwriters related to repairing such damage. Our Energy Package that was in effect on the occurrence date of Hurricane Ike had a retention requirement of $10.0 million per occurrence, which has been satisfied, and coverage policy limits of $150.0 million for damage due to named windstorms (excluding damage at certain facilities) and our Excess Policies in effect on the occurrence date of Hurricane Ike had coverage limits of $250.0 million for, among other things, removal of wreckage if mandated by any governmental authority.

As of September 30, 2013, we have recorded in ARO an estimate of $4.7 million for additional costs to be incurred related to Hurricane Ike and we have estimated this work will be completed within 12 months. Through September 30, 2013, we have received cash from our insurance carrier related to Hurricane Ike claims totaling $147.3 million. In addition, we have incurred removal of wreck costs related to Hurricane Ike, but our insurance carriers for our Excess Policies have disputed coverage terms related to removal of wreck costs, as described below.

During the fourth quarter of 2012, underwriters of our 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 seeking a determination that such Excess Policies cover removal of wreck and debris claims arising from Hurricane Ike to the extent we have first exhausted the limits of our Energy Package policies with only removal of wreck and debris claims. The court consolidated the various suits filed by underwriters. We have not yet filed any claim under such Excess Policies. As of September 30, 2013, we have spent $45.3 million and expect to incur an additional $2.1 million of costs for removal of wreck associated with platforms damaged by Hurricane Ike. 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. On July 31, 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 disagree with the Court's ruling and have appealed the decision. Removal of wreck costs are recorded in *Oil and natural gas properties and equipment* on the Balance Sheet. If we are successful in our appeal, any recoveries from claims made on these Excess Policies related to this issue will be recorded as reductions in this line item, which will reduce our DD&A rate.

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. The well control, named windstorm and physical damage coverage is effective until June 1, 2014. 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 25% 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 cover for named windstorm damage as part of our risk assessment process.

Our general and excess liability policies, effective until May 1, 2014, 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 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.

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, 2013	Nine Months Ended September 30, 2012
	(In thousands)	
Acquisition of Fairway Properties (1)	$ —	$ (2,689)
Deposit for Newfield Properties	—	22,800
Exploration (2)	149,392	59,183
Development (2)	246,105	229,255
Seismic, capitalized interest, other leasehold costs	27,595	26,623
Acquisitions and investments in oil and gas property/equipment	$ 423,092	$ 335,172

(1) The amount in 2012 represents reductions 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, 2013	Nine Months Ended September 30, 2012
	(In thousands)	
Conventional shelf	$ 132,428	$ 71,438
Deepwater	82,336	41,359
Deep shelf	57,918	8,116
Onshore	122,815	167,525
Exploration and development capital expenditures	$ 395,497	$ 288,438

Our capital expenditures for the nine months ended September 30, 2013 and 2012 were financed by cash flow from operating activities, borrowings on our revolving bank credit facility and cash on hand.

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

	Nine Months Ended September 30,			
	2013		2012	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	4	4.0	3	3.0
Non-productive	—	—	—	—
Onshore wells:				
Productive	28	27.9	37	36.9
Non-productive	—	—	—	—
Total development wells	32	31.9	40	39.9
Exploration wells:				
Offshore wells:				
Productive	1	1.0	—	—
Non Productive	1	1.0	—	—
Onshore wells:				
Productive	5	4.9	18	15.1
Non-productive	—	—	—	—
Total exploration wells	7	6.9	18	15.1
Total wells	39	38.8	58	55.0

Exploration activities – During July 2013, the A-14 well at our Ship Shoal 349 "Mahogany" field resulted in a deep shelf subsalt discovery. During the month of September 2013, on days when the well operated for a full day, the production rate was approximately 3,900 Boe/d (3,200 Boe/d to W&T, net of royalty). We hold a 100% working interest in the field. The well is currently producing from the lowest of four sands that are believed capable of production in commercial quantities.

Acquisitions and funding—We intend to continue to pursue acquisitions and joint venture opportunities during 2013 and beyond should we identify attractive opportunities. As an example, we recently complete the First Close for the Callon Properties, as described in *Financial Statements – Note 13– Subsequent Events* under Part I, Item 1 of this Form 10-Q. We are actively evaluating opportunities and seek to complement our drilling and development projects with acquisitions providing acceptable rates of return. We anticipate funding our 2013 capital budget and acquisitions with internally generated cash flow, cash on hand, borrowings under our revolving bank credit facility, and by accessing the capital markets to the extent necessary.

Lease acquisitions. During the nine months ended September 30, 2013, we acquired leasehold interest in approximately 2,200 net acres in the West Texas Permian Basin, which is near our existing holdings and increased our acreage position by approximately 10% in that area. Leasehold interests acquired in the Gulf of Mexico during the nine months ended September 30, 2013 were approximately 8,700 net acres acquired through the Department of Interior lease sale and approximately 3,400 non-operated net acres acquired from third parties.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. During the nine months ended September 30, 2013, we sold our interests in various fields. Cumulatively, these transactions and other minor transactions and adjustments resulted in the receipt of net proceeds of $11.9 million and the reversal of $19.6 million of ARO. One of the transactions was structured for "like-kind" exchange tax treatment, which resulted in funds being deposited at an intermediary until investments are made in similar properties and such funds are reported in *Restricted cash and cash equivalents* on the balance sheet as of September 30, 2013. During the nine months ended September 30, 2012, we sold our interest in one field, received net proceeds of $30.5 million and reversed $4.0 million of ARO. The sale was structured to receive like-kind exchange tax treatment and investments in similar properties were made from the funds received. See *Financial Statements – Note 2– Acquisitions and Divestitures* under Part I, Item 1 of this Form 10-Q for additional information.

Capital Expenditure Budget for 2013. Our total capital expenditure budget is $550.0 million for 2013. The capital expenditure budget does not include actual, planned or potential acquisitions. The budget is generally allocated as 60% for exploration and 40% for development and these percentages include amounts for facilities capital, recompletions, seismic data, leasehold interests and other items. Geographically, the budget includes 65% for offshore properties and 35% for onshore properties. Our 2013 capital budget is subject to change as conditions warrant and we strive to be as flexible as possible.

Income 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. During the nine months ended September 30, 2012, we made income tax payments of $14.1 million and received refunds of $0.4 million. For the remainder of 2013, we expect a substantial amount of our income tax will be deferred and expect payments to be primarily related to alternative minimum tax. As of September 30, 2013, $9.5 million of the refunds received in 2013 have been accounted for as unrecognized tax benefits. We have $41.4 million of net operating loss carryforwards available to offset future taxable income in 2013 and forward. We also have $21.6 million of alternative minimum tax credit carryforwards available to be utilized in 2013 and forward.

Dividends. During the nine months ended September 30, 2013 and 2012, we paid regular cash dividends per common share of $0.26 and $0.24, respectively. On November 6, 2013, our board of directors declared a cash dividend of $0.10 per common share, payable on December 3, 2013 to shareholders of record on November 18, 2013.

Contractual obligations. Updated information on certain contractual obligations is provided in *Financial Statements –Note 4 – Asset Retirement Obligations* and *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q. As of September 30, 2013, drilling rig commitments were approximately $18.1 million compared to $36.5 million as of December 31, 2012. The current drilling rig commitments all expire within one year from September 30, 2013. In addition, we entered into an agreement, effective April 1, 2013 and expiring March 31, 2017, with a group of companies for access to a comprehensive well-containment solution made up of certain equipment, procedures, and processes to be activated in the event of an offshore spill. The remaining commitment as of September, 2013 was $6.2 million. Except for scheduled utilization, other contractual obligations as of September 30, 2013 did not change materially from the disclosures in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2012.

Critical Accounting Policies

Our significant accounting policies are summarized in *Note 1 of Notes to Consolidated Financial Statements* included in our Annual Report on Form 10-K for the year ended December 31, 2012. Also refer to the *Notes to Condensed Consolidated Financial Statements* under Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities* which applies to certain items in the statement of financial position (balance sheet), and was further clarified in January 2013 by ASU 2013-01, *Balance Sheet (Topic 210):Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which clarified the scope of ASU 2011-11 to derivative instruments, repurchase agreements and securities lending transactions. The effective date for the amendments is for annual periods beginning after January 1, 2013, and interim periods within those annual periods. ASU 2011-11 requires disclosures of the gross and net amounts for items eligible for offset in the balance sheet. Our derivative financial instruments are subject to master netting agreements and we record our derivative financial instruments on a gross basis by contract; therefore, the revisions related to disclosing our derivative financial instruments on a net basis. Other items of the ASUs were not applicable to us.

In February 2013, the FASB issued ASU 2013-04, *Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date,* which requires an entity that is joint and severally liable to measure the obligation as the sum of the amount the entity has agreed with co-obligors to pay and any additional amount it expects to pay on behalf of one or more co-obligors. Required disclosures include a description of the nature of the arrangement, how the liability arose, the relationship with co-obligors and the terms and conditions of the arrangement. The effective date for the amendment is for annual periods beginning after December 15, 2013, and interim periods within those annual periods. The amendment is to be applied retrospectively to all prior periods presented. We are currently assessing the impact of ASU 2013-04 to determine the effects on the balance sheet and disclosures, if any.

In July 2013, the FASB issued ASU 2013-11,*Income Taxes (Topic 740); Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a similar Tax Loss, or a Tax Credit Carryforward Exists a consensus of the FASB Emerging Task Force*, which provided guidance on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This guidance requires an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. The amendment is effective for annual periods and interim periods beginning after December 15, 2013. Early adoption is permitted and the amendment is to be applied prospectively. The Company is currently assessing the impact of ASU 2013-11 to determine the effects on the balance sheet and disclosures, if any.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the nine months ended September 30, 2013 did not change materially from the disclosures in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2012. 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, 2012.

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 2013 and the year 2014. As of September 30, 2013, these derivative contracts had a notional quantity of 2.9 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 *Financial Statements – Note 5– Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of September 30, 2013, we had $137.0 million outstanding on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the rates for the LIBOR and the margin, which ranges from 2.00% 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 Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer have each concluded that as of September 30, 2013 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 Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended September 30, 2013, 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

Cameron Parish Louisiana Claim. Since 2009, certain Cameron Parish landowners have filed suits in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and its Chief Executive Officer, Tracy W. Krohn, as well as several other defendants unrelated to us. In their lawsuits, plaintiffs alleged that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and they are seeking compensatory and punitive damages. During 2012 and for the nine months ended September 30, 2013, we settled claims with certain landowners and paid $10.0 million and $1.3 million, respectively.

Qui Tam Litigation. On September 21, 2012, we were served with a complaint in a *qui tam* action filed under the federal False Claims Act by an employee of one of our contractors. The lawsuit, *United States ex rel. Comeaux v. W&T Offshore, Inc., et al.; CA No. 10-494*, was filed in the United States District Court for the Eastern District of Louisiana, against us and three other working interest owners related to claims associated with three of our operated production platforms. A *qui tam* action, also known as a "whistleblower" action, is a lawsuit brought by a private citizen seeking civil penalties or damages against a person or company on behalf of the government for alleged violations of law. If the claims are successful, the person filing the suit may recover a percentage of the damages or penalty from the lawsuit as a reward for exposing a wrongdoing and recovering funds on behalf of the government. This matter was more fully described in the Company's Annual Report on Form 10-K for the year ended December 31, 2012.

On November 5, 2013, the court granted the Company's motion to dismiss and the complaint was dismissed with prejudice. If a motion for reconsideration or an appeal is made, the Company intends to vigorously defend the claims made in this lawsuit. The Company has determined that the likelihood of an adverse outcome is remote, and accordingly, no accrual has been made.

Insurance Claims. During the fourth quarter of 2012, underwriters of our 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 seeking a determination that such Excess Policies cover removal of wreck and debris claims arising from Hurricane Ike to the extent we have first exhausted the limits of our Energy Package policies with only removal of wreck and debris claims. The court consolidated the various suits filed by underwriters. We have not yet filed any claim under such Excess Policies. As of September 30, 2013, we have spent $45.3 million to date and expect to incur an additional $2.1 million of costs for removal of wreck associated with platforms damaged by Hurricane Ike. 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. On July 31, 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 disagree with the Court's ruling and have appealed the decision. Removal of wreck costs are recorded in *Oil and natural gas properties and equipment* on the Balance Sheet. If we are successful in our appeal, any recoveries from claims made on these Excess Policies related to this issue will be recorded as reductions in this line item, which will reduce our DD&A rate.

From time to time, we are party to other litigation or legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Except for the matters noted above, we are not involved in any legal proceedings nor are we party to any pending or threatened claims that could, individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flow or results of operations.

Proceedings by Government Authorities. During the third quarter of 2013, we paid $0.2 million of civil penalties assessed by BSEE for non-compliance with certain regulations. The penalties related to incidents at two of our offshore platforms, with one incident involving a crane operation and one incident involving a hatch closure issue.

Item 1A. Risk Factors

Investors should carefully consider the risk factors included under *Risk Factors* under Part I, Item 1A in our Annual Report on Form 10-K for the year ended December 31, 2012, 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. Notwithstanding the matters discussed herein, there have been no material changes in our risk factors as previously disclosed in Part I, Item 1A in our Annual Report on Form 10-K for the year ended December 31, 2012.

Item 6. Exhibits

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

SIGNA TURE

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 8, 2013.

W&T OFFSHORE, INC.

By: /s/ JOHN D. GIBBONS

John D. Gibbons
Senior Vice President, Chief Financial Officer and Chief Accounting Officer, duly authorized to sign on behalf of the
registrant

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006)
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
10.1@	Form of 2013 Executive Annual Cash Award. (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q, filed August 8, 2013 (File No. 001-32414))
10.2@	Form of 2013 RSU Executive Award. (Incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q, filed August 8, 2013 (File No. 001-32414))
10.3@	Form of 2013 Time Based RSU Executive Agreement. (Incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q, filed August 8, 2013 (File No. 001-32414))
10.4@	Tracy W. Krohn 2013 Annual Award. (Incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q, filed August 8, 2013 (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.
@	Compensation agreement
**	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.;

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 8, 2013

/s/ Tracy W. Krohn
Tracy W. Krohn
Chairman, Chief Executive Officer and Director

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.;

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 8, 2013

/s/ John D. Gibbons
John D. Gibbons
Senior Vice President, Chief Financial Officer and
Chief Accounting 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, 2013 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 8, 2013

/s/ Tracy W. Krohn
Tracy W. Krohn
Chairman, Chief Executive Officer and Director

Date: November 8, 2013

/s/ John D. Gibbons
John D. Gibbons
Senior Vice President, Chief Financial Officer and
Chief Accounting Officer