Table of Contents

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, 2011

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 2, 2011, there were 74,461,440 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, 2011	December 31, 2010
	(In thousands, except share data) (Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 7,666	$ 28,655
Receivables:		
Oil and natural gas sales	82,824	79,911
Joint interest and other	18,199	25,415
Insurance	1,664	1,014
Total receivables	102,687	106,340
Deferred income taxes	—	5,784
Prepaid expenses and other assets	45,545	23,426
Total current assets	155,898	164,205
Property and equipment – at cost:		
Oil and natural gas properties and equipment (full cost method, of which $152,646 at September 30, 2011 and $65,419 at December 31, 2010 were excluded from amortization)	5,858,814	5,225,582
Furniture, fixtures and other	16,158	15,841
Total property and equipment	5,874,972	5,241,423
Less accumulated depreciation, depletion and amortization	4,240,069	4,021,395
Net property and equipment	1,634,903	1,220,028
Restricted deposits for asset retirement obligations	34,675	30,636
Deferred income taxes	—	2,819
Other assets	15,723	6,406
Total assets	$ 1,841,199	$ 1,424,094
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 80,997	$ 80,442
Undistributed oil and natural gas proceeds	34,706	25,240
Asset retirement obligations	128,584	92,575
Accrued liabilities	30,294	25,827
Income taxes payable	1,657	17,552
Income taxes deferred – current portion	5,293	—
Total current liabilities	281,531	241,636
Long-term debt	694,000	450,000
Asset retirement obligations, less current portion	265,547	298,741
Deferred income taxes	45,438	—
Other liabilities	8,686	11,974
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 2,000,000 shares authorized; 0 issued at September 30, 2011 and December 31, 2010	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 77,332,969 issued and 74,463,796 outstanding at September 30, 2011; 77,343,520 issued and 74,474,347 outstanding at December 31, 2010	1	1
Additional paid-in capital	383,966	377,529
Retained earnings	186,197	68,380
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	545,997	421,743
Total liabilities and shareholders' equity	$ 1,841,199	$ 1,424,094

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,	
	2011	2010	2011	2010
	(In thousands, except per share data) (Unaudited)			
Revenues	$ 245,371	$ 169,575	$ 709,148	$ 518,827
Operating costs and expenses:				
Lease operating expenses	58,899	34,371	159,901	122,194
Production taxes	1,050	276	2,183	788
Gathering and transportation	4,853	4,607	13,203	12,920
Depreciation, depletion and amortization	77,056	69,051	218,674	201,870
Asset retirement obligation accretion	7,399	6,264	23,243	18,676
General and administrative expenses	18,104	13,389	54,235	38,143
Derivative (gain) loss	(17,323)	4,770	(10,815)	(8,500)
Total costs and expenses	150,038	132,728	460,624	386,091
Operating income	95,333	36,847	248,524	132,736
Interest expense:				
Incurred	14,721	10,485	36,913	32,319
Capitalized	(3,163)	(1,345)	(6,654)	(4,090)
Loss on extinguishment of debt	2,031	—	22,694	—
Interest income	6	150	22	632
Income before income tax expense	81,750	27,857	195,593	105,139
Income tax expense	28,822	669	68,841	7,766
Net income	$ 52,928	$ 27,188	$ 126,752	$ 97,373
Basic and diluted earnings per common share	$ 0.70	$ 0.36	$ 1.68	$ 1.30
Dividends declared per common share	$ 0.04	$ 0.04	$ 0.12	$ 0.10

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

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

	Common Stock Outstanding		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Total Shareholders' Equity
	Shares	Value			Shares	Value	
				(In thousands) (Unaudited)			
Balances at December 31, 2010	74,474	$ 1	$377,529	$ 68,380	2,869	$(24,167)	$ 421,743
Cash dividends	—	—	—	(8,935)	—	—	(8,935)
Share-based compensation	—	—	6,437	—	—	—	6,437
Restricted stock issued, net of forfeitures	(10)	—	—	—	—	—	—
Net income	—	—	—	126,752	—	—	126,752
Balances at September 30, 2011	74,464	$ 1	$383,966	$186,197	2,869	$(24,167)	$ 545,997

See Notes to Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In thousands) (Unaudited)	
Operating activities:		
Net income	$ 126,752	$ 97,373
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	241,917	220,546
Amortization of debt issuance costs	1,401	1,004
Loss on extinguishment of debt	22,694	—
Share-based compensation	6,437	3,576
Derivative (gain) loss	(10,815)	(8,500)
Cash payments on derivative settlements	(9,239)	(410)
Deferred income taxes	59,442	6,483
Changes in operating assets and liabilities:		
Oil and natural gas receivables	(2,913)	3,630
Joint interest and other receivables	7,465	29,542
Insurance receivables	18,971	36,763
Income taxes	(15,894)	84,152
Prepaid expenses and other assets	(22,601)	(1,464)
Asset retirement obligations	(51,349)	(62,620)
Accounts payable and accrued liabilities	23,892	(30,148)
Other liabilities	(109)	12,950
Net cash provided by operating activities	396,051	392,877
Investing activities:		
Acquisitions of property interests in oil and natural gas properties	(434,582)	(116,589)
Investment in oil and natural gas properties and equipment	(185,222)	(127,427)
Proceeds from sales of oil and natural gas properties and equipment	15	1,335
Purchases of furniture, fixtures and other	(318)	(405)
Net cash used in investing activities	(620,107)	(243,086)
Financing activities:		
Issuance of 8.5% Senior Notes	600,000	—
Repurchase of 8.25% Senior Notes	(450,000)	—
Borrowings of long-term debt – revolving bank credit facility	512,000	427,500
Repayments of long-term debt – revolving bank credit facility	(418,000)	(427,500)
Repurchase premium and debt issuance costs	(31,997)	—
Dividends to shareholders	(8,936)	(7,467)
Net cash provided (used) in financing activities	203,067	(7,467)
Increase (decrease) in cash and cash equivalents	(20,989)	142,324
Cash and cash equivalents, beginning of period	28,655	38,187
Cash and cash equivalents, end of period	$ 7,666	$ 180,511

See Notes to Condensed Consolidated Financial Statements.

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

1. Basis of Presentation

Operations. W&T Offshore, Inc. 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 acquisition, exploitation, exploration and development of oil and natural gas properties. W&T has recently diversified its operations by expanding onshore in Texas.

Interim Financial Statements. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") for interim financial information 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. 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 thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

Reclassifications. Certain reclassifications have been made to the prior periods' financial statements to conform to the current presentation.

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.

2. Acquisitions

On August 10, 2011, we completed the acquisition of Shell Offshore Inc.'s ("Shell") 64.3% interest in the Fairway Field along with a like interest in the associated Yellowhammer gas processing plant (the "Fairway Properties"). The stated purchase price was $55.0 million, subject to certain adjustments, including adjustments from an effective date of September 1, 2010 until the closing date of August 10, 2011. Taking into account such adjustments, as of September 30, 2011, the cash purchase price component was $40.0 million. The decrease of $15.0 million primarily reflects net production cash flow, partially offset by plugging and abandonment costs incurred, from the effective date of September 1, 2010 to the closing date. The purchase price is subject to further post-effective date adjustments and final settlement is expected to occur in the first quarter of 2012. We assumed the asset retirement obligations ("ARO") associated with the properties and plant which we have currently estimated to be $7.8 million. We are finalizing our assessment of the fair values of the assets acquired and liabilities assumed. Therefore, the purchase price allocation as described in the following table is preliminary and is subject to change. The acquisition was funded from borrowings under our revolving bank credit facility.

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

The following table presents the preliminary purchase price allocation for the acquisition of the Fairway Properties (in thousands):

Oil and natural gas properties and equipment	$ 47,800
Asset retirement obligations – non-current	(7,812)
Total cash paid	$ 39,988

On May 11, 2011, we completed the acquisition of approximately 21,900 gross acres (21,500 net acres) of oil and gas leasehold interests in the West Texas Permian Basin (the "Permian Basin Properties") from Opal Resources LLC and Opal Resources Operating Company LLC ("Opal"). The stated purchase price was $366.3 million, subject to certain adjustments, including adjustments from an effective date of January 1, 2011 until the closing date of May 11, 2011. Taking into account such adjustments, as of September 30, 2011, the purchase price was $397.1 million. The increase of $30.8 million primarily reflects drilling costs in excess of cash flow from the effective date of January 1, 2011 to the closing date. Although further adjustments could occur to the purchase price, no further adjustments are expected at this time. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

The following table presents the purchase price allocation for the acquisition of the Permian Basin Properties (in thousands):

Oil and natural gas properties and equipment (1)	$ 397,119
Asset retirement obligations – non-current	(382)
Long-term liability	(2,143)
Total cash paid	$ 394,594

(1) As of September 30, 2011, $82.6 million has been recorded as unproved properties which are excluded from the full cost pool and amortization base.

For the three months ended September 30, 2011, the Permian Basin Properties and the Fairway Properties accounted for $21.6 million of revenue, $8.8 million of direct operating expenses, $7.2 million of depreciation, depletion, amortization and accretion ("DD&A") and $2.0 million of income taxes, resulting in $3.6 million of net income. For the nine months ended September 30, 2011, the Permian Basin Properties and the Fairway Properties accounted for $32.8 million of revenue, $10.7 million of direct operating expenses, $9.6 million of DD&A and $4.4 million of income taxes, resulting in $8.1 million of net income. Such amounts are for the period from each respective close date to September 30, 2011. The net income attributable to these properties does not reflect certain expenses, such as general and administrative expenses 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 Permian Basin Properties and the Fairway 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 these acquisitions for the three and nine months ended September 30, 2011 were $0.8 million and $1.4 million, respectively, and are included in general and administrative expenses.

Pro forma financial statements have been prepared due to the Permian Basin Properties being significant. The Fairway Properties acquisition, which was not significant, was combined with the Permian Basin Properties to disclose the effect of both acquisitions. The unaudited pro forma financial information was computed as if these two acquisitions had been completed on January 1, 2010. The historical financial information is derived from the unaudited historical consolidated financial statements of W&T and the unaudited historical statements of the sellers.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Permian Basin Properties and the Fairway Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2010. If the transactions 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 the sellers, realized sales prices may have been different and costs of operating the properties may have been different. The following table presents a summary of our pro forma condensed combined statements of income for the nine months ended September 30, 2011 and 2010 (in thousands except earnings per share):

	Three Months Ended, September 30,		Nine Months Ended, September 30,	
	2011	2010	2011	2010
Revenue	$ 250,257	$ 187,163	$ 761,531	$ 574,820
Net income	56,207	25,449	139,134	95,467
Basic and diluted earnings per common share	0.74	0.34	1.84	1.28

The purchase price of both acquisitions may be subject to further adjustments. For these pro forma financial statements, we assumed the transactions were financed with borrowings from the revolving bank credit facility because the cash and cash equivalents balances for the assumed acquisition date was less than the cash and cash equivalents on hand used on the actual closing dates of the two acquisitions. Also, we assumed that the revolving bank credit facility capacity would have been increased due to the increase in reserves.

The following adjustments were made in the preparation of the condensed combined statement of income:

(a) Revenues and direct operating expenses for the Permian Basin Properties and the Fairway Properties were derived from the historical records of the sellers up to the respective closing dates.

(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Permian Basin Properties and Fairway Properties costs, reserves and production into the computation. The purchase price allocation included $82.6 million allocated to the pool of unevaluated properties for oil and gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties.

(c) Asset retirement obligations and related accretion were estimated by W&T management.

(d) Incremental transaction expenses related to the acquisitions for the three and nine months ended September 30, 2011 were $0.8 million and $1.4 million, respectively, and were assumed to be funded from cash on hand.

(e) Interest expense was computed using interest rates that were in effect during the applicable time period and we assumed that six-month LIBOR borrowings were made as allowed under the revolving bank credit facility. The assumed interest rates ranged from 3.1% to 3.5%. A reduction in the revolving bank credit facility commitment fee related to the assumed borrowings was netted against the computed incremental interest expense.

(f) 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.

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

During 2010, we closed on two acquisition transactions. The first closed on April 30, 2010. Through our wholly-owned subsidiary, W&T Energy VI, LLC (“Energy VI”), we acquired all of Total E&P USA’s (“Total”) interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico and assumed the asset retirement obligations (“ARO”) for plugging and abandonment of the acquired interests. The adjusted purchase price was $121.3 million. The properties acquired from Total (the “Matterhorn/Virgo Properties”) are producing interests and include a 100% working interest in the Matterhorn field (Mississippi Canyon block 243) and a 64% working interest in the Virgo field (Viosca Knoll blocks 822 and 823). The second closed on November 4, 2010. Through Energy VI, we acquired all of Shell's interests, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico and assumed the ARO for plugging and abandonment of the acquired interests. The adjusted purchase price was $134.2 million. The properties acquired from Shell (the "Tahoe/Droshky Properties") are producing interests and include a 70% working interest in the Tahoe field (Viosca Knoll 783), 100% working interest in the Southeast Tahoe field (Viosca Knoll 784) and a 6.25% of 8/8ths overriding royalty interest in the Droshky field (Green Canyon 244).

3. Hurricane Remediation and Insurance Claims

During the third quarter of 2008, Hurricane Ike and, to a much lesser extent, Hurricane Gustav caused property damage and disruptions to our exploration and production activities. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10 million per occurrence to be satisfied by us before we could be indemnified for losses. In the fourth quarter of 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our facilities of marginal significance) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The damage we incurred as a result of Hurricane Gustav was below our retention amount.

Below is a summary of remediation costs and amounts approved for payments related to Hurricanes Ike and Gustav that were included in lease operating expense (in thousands), with bracketed amounts representing credits to expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Incurred and reversals of accruals	$ (4)	$ 413	$ 71	$ (1,465)
Plus amounts returned to insurers	—	—	1,241	—
Less amounts approved for payment by insurers	(537)	(7,522)	(1,124)	(9,879)
Included in lease operating expense	$ (541)	$ (7,109)	$ 188	$(11,344)

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. Incurred expenses included revisions of previous estimates. Amounts in 2011 include return of reimbursements that were previously received by us related to prepayments based on preliminary estimates. See Note 4 for additional information about the impact of hurricane related items on our asset retirement obligations.

Below is a reconciliation of our insurance receivables from December 31, 2010 to September 30, 2011 (in thousands):

Balance, December 31, 2010	$ 1,014
Costs approved under our insurance policies, net	19,506
Payments received, net	(18,856)
Balance, September 30, 2011	$ 1,664

At September 30, 2011 and December 31, 2010, substantially all of the amounts in insurance receivables relate to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike. We expect that our available cash and cash equivalents, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricane Ike.

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

4. Asset Retirement Obligations

Our asset retirement obligations primarily represent 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 asset retirement obligations is as follows (in thousands):

Balance, December 31, 2010	$ 391,316
Liabilities settled	(51,349)
Accretion of discount	23,243
Liabilities assumed through acquisition	8,194
Liabilities incurred	451
Revisions of estimated liabilities due to Hurricane Ike	4,763
Revisions of estimated liabilities – all other	17,513
Balance, September 30, 2011	394,131
Less current portion	128,584
Long-term	$ 265,547

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 oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. We do not enter into derivative instruments for speculative trading purposes. Our derivative instruments currently consist of commodity option contracts. We are exposed to credit loss in the event of nonperformance by the counterparties; however, we do not currently anticipate any of our counterparties being unable to fulfill their contractual obligations.

We account for derivative contracts in accordance with GAAP, which requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Changes in a derivative's fair value are required to be recognized currently in earnings unless specific hedge accounting criteria are met at the time we enter into a derivative contract. We have elected not to designate our commodity derivatives as hedging instruments. For additional information about fair value measurements, refer to Note 7.

Commodity Derivative: During 2010, we entered into commodity option contracts to manage a portion of our exposure to commodity price risk from sales of oil through December 31, 2012. While these contracts are intended to reduce the effects of price volatility, they may also limit future income from favorable price movements. As of September 30, 2011, our open commodity derivatives were as follows:

Zero Cost Collars – Oil

Effective Date	Termination Date	Notional Quantity (Bbls)	Weighted Average NYMEX Contract Price		Fair Value Asset (in thousands)
			Floor	Ceiling	
10/1/2011	12/31/2011	392,100	$ 75.00	$ 95.58	$ 1,053
1/1/2012	3/31/2012	364,000	75.00	97.88	1,449
4/1/2012	6/30/2012	364,000	75.00	97.88	1,390
7/1/2012	9/30/2012	124,000	75.00	97.88	444
10/1/2012	12/31/2012	251,000	75.00	98.99	836
		1,495,100	$ 75.00	$ 97.46	$ 5,172

At September 30, 2011, $4.4 million and $0.8 million were included in current assets and other long-term assets, respectively, related to our commodity derivative contracts. At December 31, 2010, $9.5 million and $5.4 million were included in accrued liabilities and other long-term liabilities, respectively, related to our commodity derivative contracts. Our derivative gain for the three months ended September 30, 2011 includes realized losses of $0.9 million and unrealized gains of $18.2 million related to our commodity derivatives. Our derivative gain for the nine months ended September 30, 2011 includes realized losses of $9.2 million and unrealized gains of $20.0 million related to our commodity derivatives. Our derivative loss for the three months ended September 30, 2010 includes a realized gain of $1.1 million and an unrealized loss of $5.9 million related to our commodity derivatives. Our derivative gain for the nine months ended September 30, 2010 includes realized and unrealized gains of $4.3 million and $4.5 million, respectively, related to our commodity derivatives.

Interest Rate Swap: Our interest rate swap contract with a fixed interest rate of 5.21% expired in August 2010. During the three months ended September 30, 2010, we recognized an unrealized gain of $1.0 million and a realized loss of $1.0 million for this contract. During the nine months ended September 30, 2010, we recognized an unrealized gain of $4.4 million and a realized loss of $4.7 million for this contract.

6. Long-Term Debt

On June 10, 2011, we issued $600 million of our senior notes at par with an interest rate of 8.5% and maturity date of June 15, 2019 (the "8.5% Senior Notes"). Interest is payable semi-annually in arrears on June 15 and December 15 of each year beginning on December 15, 2011. The 8.5% Senior Notes are unsecured and are fully and unconditionally guaranteed by certain of our subsidiaries. The restrictive covenants and redemption provisions of the 8.5% Senior Notes are substantially similar to the terms of the 8.25% Senior Notes due 2014 (the "8.25% Senior Notes"). At September 30, 2011, the outstanding balance of our 8.5% Senior Notes was $600 million and was classified at their carrying value as long-term debt. The estimated annual effective interest rate on the 8.5% Senior Notes is 8.7% which includes amortization of debt issuance costs. At September 30, 2011, the estimated fair value of the 8.5% Senior Notes was approximately $579 million. For additional details about fair value measurements, refer to Note 7.

In June and July of 2011, we used a portion of the net proceeds from the issuance of the 8.5% Senior Notes to repurchase all of our 8.25% Senior Notes, which had a principal amount of $450 million. Costs of $22.0 million related to repurchasing the 8.25% Senior Notes, which included repurchase premiums and the unamortized debt issuance costs, are included in the statement of income within the line item classification, *Loss on extinguishment of debt.* At December 31, 2010, the outstanding balance of our 8.25% Senior Notes was $450 million and was classified at their carrying value as long-term debt. At December 31, 2010, the estimated fair value of the 8.25% Senior Notes was approximately $441 million. For additional details about fair value measurements, refer to Note 7.

On May 5, 2011, we entered into a Fourth Amended and Restated Credit Agreement (the "Credit Agreement") which provides a revolving bank credit facility with an initial borrowing base of $525 million. This is a secured facility that is collateralized by our oil and natural gas properties. The Credit Agreement terminates on May 5, 2015 and replaces the prior Third Amended and Restated Credit Agreement (the "Prior Credit Agreement"), which would have expired July 23, 2012. The pricing terms and restrictive covenants of the Credit Agreement are substantially similar to the terms of the Prior Credit Agreement. Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility.

Pursuant to the Credit Agreement, the initial borrowing base was adjusted due to the following two items. First, the initial borrowing base was reduced by $37.5 million due to the issuance of the 8.5% Senior Notes of $600 million. Second, the borrowing base was increased by $50 million due to the consummation of the acquisition of the Fairway Properties in August 2011. After these two transactions, our borrowing base was $537.5 million as of September 30, 2011. In October 2011, the borrowing base was re-determined by our lenders and increased to $575 million.

The Credit Agreement contains covenants that restrict, among other things, the payment of cash dividends and share repurchases of up to $60 million per year, borrowings other than from the revolving bank credit facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. Letters of credit may be issued up to $90 million, provided availability under the revolving bank credit facility exists. 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 as such ratios are defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of September 30, 2011.

Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate ("LIBOR") plus a margin that varies from 2.00% to 2.75% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the applicable margin ranging from 1.00% to 1.75% plus the highest of the (a) Prime Rate, (b) Federal Funds Rate plus 0.50%, and (c) LIBOR plus 1.0%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%. The estimated annual effective interest rate was 3.7% for the nine months ended September 30, 2011 for borrowings under the Credit Agreement and the Prior Credit Agreement and includes amortization of debt issuance costs, and excludes commitment fees and other costs.

Unamortized debt issuance costs of $0.7 million related to the Prior Credit Agreement were written off and are included in the statement of income within the line item classification, *Loss on extinguishment of debt.*

At September 30, 2011, we had $94 million in borrowings and $0.5 million in letters of credit outstanding under the revolving bank credit facility. At December 31, 2010, we had no borrowings and $0.4 million in letters of credit outstanding under the revolving bank credit facility provided by the Prior Credit Agreement.

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. 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 fair value of our senior notes is based on quoted prices. The market for our senior notes is not an active market; therefore the fair value is classified within Level 2. The senior notes are reported in the balance sheet at their carrying value and their fair value is reported 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. As allowed by the Plan, in August 2010 and August 2011, the Company granted restricted stock units ("RSUs") to certain of its employees and in January 2011, the Company granted restricted stock to one 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 Company achieving certain predetermined performance criteria. The RSUs vest at the end of a specified deferral period. Prior to 2010, the Company granted only restricted stock to its employees. In 2011 and in prior years, restricted stock was granted to the Company's non-employee directors under the Director Compensation Plan. In addition to share-based compensation, the Company may grant 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 actually vest.

At September 30, 2011, there were 2,157,482 shares of common stock available for award under the Plan and 568,783 shares of common stock available for award under the Directors Compensation Plan.

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

Restricted Stock: The Company currently has unvested restricted shares outstanding issued to employees and 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.

A summary of share activity related to restricted stock for the nine months ended September 30, 2011 is as follows:

	Restricted Stock	
	Shares	Weighted Average Grant Date Fair Value Per Share
Outstanding restricted shares, December 31, 2010	470,392	$ 7.42
Granted	20,433	25.45
Vested	(24,633)	13.26
Forfeited	(30,984)	6.83
Outstanding restricted shares, September 30, 2011	435,208	7.98

At September 30, 2011, the composition of our restricted stock awards outstanding, by year granted, was as follows:

	Shares
Employees – granted in:	
2011	5,325 (1)
2009	380,675 (2)
Non-employee directors – granted in:	
2011	15,108 (3)
2010	23,330 (4)
2009	10,770 (5)
Total	435,208

Vesting is expected to occur, less any forfeitures, as follows:

(1) Equal installments in December 2011 and December 2012.
(2) December 2011.
(3) Equal installments in May 2012, 2013 and 2014.
(4) Equal installments in May 2012 and 2013.
(5) May 2012.

The grant date fair value of restricted stock granted during the nine months ended September 30, 2011 and 2010 was $0.5 million and $0.4 million, respectively. The fair value of the shares that vested during the nine months ended September 30, 2011 and 2010 was $0.6 million and $0.1 million, respectively.

Restricted Stock Units: During 2011, the Company awarded to certain employees RSUs that are 100% contingent upon meeting a specified performance requirement for the year 2011. If the performance requirement is achieved, the RSUs awarded in 2011 will earn dividend equivalents effective January 1, 2012 at the same rate as dividends paid on our common stock. During 2010, the Company awarded to certain employees RSUs that were 100% contingent upon meeting a specified performance requirement, which was achieved in 2010. Effective January 2011, RSUs awarded in 2010 earn dividend equivalents at the same rate as dividends paid on our common stock. RSUs awarded in both years are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period.

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

A summary of share activity related to RSUs for the nine months ended September 30, 2011 is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding RSUs, December 31, 2010	1,266,617	$ 9.36
Granted	528,042	26.93
Vested	—	—
Forfeited	(65,660)	11.44
Outstanding RSUs, September 30, 2011 (1)	1,728,999	14.65

(1) Subject to employment conditions, 1,208,714 and 520,285 RSU's will vest in December 2012 and December 2013, respectively.

During the nine months ended September 30, 2011 and 2010, the fair value of RSUs granted was $14.2 million and $12.0 million, respectively. No vesting of RSUs occurred in either time period.

Share-Based Compensation: A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit for the three and nine months ended September 30, 2011 and 2010 is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Share-based compensation expense from:				
Restricted stock	$ 593	$ 807	$1,784	$2,750
Restricted stock units	2,182	826	4,653	826
Total	$2,775	$1,633	$6,437	$3,576
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$ 971	$ 572	$2,253	$1,252

Cash-based Incentive Compensation: As defined by the Plan, annual cash-based incentive awards may be granted to eligible employees. These awards are performance-based awards consisting of one or more business criteria and 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.

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

Incentive Compensation: A summary of incentive compensation expense for the three and nine months ended September 30, 2011 and 2010 is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Share-based compensation expense included in:				
Lease operating expense	$ 116	$ 171	$ 349	$ 599
General and administrative	2,659	1,462	6,088	2,977
Total charged to operating income	2,775	1,633	6,437	3,576
Cash-based incentive compensation included in:				
Lease operating expense	697	507	2,836	1,284
General and administrative	3,024	2,564	9,175	5,475
Total charged to operating income	3,721	3,071	12,011	6,759
Total incentive compensation charged to operating income	$ 6,496	$ 4,704	$18,448	$10,335

As of September 30, 2011, unrecognized share-based compensation expense related to our outstanding restricted shares and RSUs was $1.1 million and $18.2 million, respectively. Unrecognized compensation expense will be recognized through April 2014 for restricted shares and November 2013 for RSUs.

9. Income Taxes

Income tax expense of $28.8 million and $68.8 million was recorded during the three and nine months ended September 30, 2011, respectively. Our effective tax rate for the three and nine months ended September 30, 2011 was 35.3% and 35.2%, respectively, which approximated the federal and state statutory rates. Income tax expense of $0.7 million and $7.8 million was recorded during the three and nine months ended September 30, 2010, respectively. Our effective tax rate for the three and nine months ended September 30, 2010 was 2.4% and 7.4%, respectively, and primarily reflects a reduction in our valuation allowance that was recorded in prior years.

Exclusive of interest, the amount of unrecognized tax benefit recorded in other liabilities as of September 30, 2011 and December 31, 2010 was $ 3.3 million and $3.6 million, respectively. We recognize interest and penalties related to unrecognized tax benefits in income tax expense and these amounts were immaterial for the nine months ended September 30, 2011 and 2010. The tax years from 2008 through 2010 remain open to examination by the applicable tax jurisdictions.

10. Earnings Per Share

The following table presents the calculation of basic earnings per common share for the three and nine months ended September 30, 2011 and 2010 (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	$ 52,928	$ 27,188	$ 126,752	$ 97,373
Less portion allocated to nonvested shares	1,118	351	2,680	1,304
Net income allocated to common shares	$ 51,810	$ 26,837	$ 124,072	$ 96,069
Weighted average common shares outstanding	74,028	73,675	74,017	73,668
Basic and diluted earnings per common share	$ 0.70	$ 0.36	$ 1.68	$ 1.30
Shares excluded due to being anti-dilutive (weighted-average)	1,995	1,787	1,798	1,310

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

11. Dividends

During the nine months ended September 30, 2011, we paid regular cash dividends of $0.04 per common share per quarter. During the nine months ended September 30, 2010, we paid regular cash dividends of $0.04, $0.03 and $0.03 per common share per quarter, respectively. On October 31, 2011, our board of directors declared a cash dividend of $0.04 per common share, payable on December 1, 2011 to shareholders of record on November 16, 2011.

12. Contingencies

The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the Environmental Protection Agency, is conducting a federal grand jury investigation of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico. We are fully cooperating with the investigation. The United States Attorney's Office has recently informed us that they are continuing with their investigation with the intent to seek a criminal disposition. We are not able at this time to estimate our potential exposure, if any, related to this matter.

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.

Table of Contents

13. Supplemental Guarantor Information

Our payment obligations under the 8.5% Senior Notes and the Credit Agreement (see Note 6) are fully and unconditionally guaranteed by certain of our wholly-owned subsidiaries, Energy VI, which includes the operations of acquisitions closed in 2010 as described in Note 2, and W&T Energy VII, LLC which does not have any active operations, (together, the "Guarantor Subsidiaries").

The following unaudited condensed consolidating financial information presents the financial condition, results of operations and cash flows of W&T Offshore, Inc. and other consolidated subsidiaries ("Parent Company") and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. Consolidated subsidiaries other than the Guarantor Subsidiaries are considered "minor" under applicable accounting rules of the SEC.

Condensed Consolidating Balance Sheet as of September 30, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 7,666	$ —	$ —	$ 7,666
Receivables:				
Oil and natural gas sales	61,368	21,456	—	82,824
Joint interest and other	18,199	—	—	18,199
Insurance	1,664	—	—	1,664
Income taxes	62,592	—	(62,592)	—
Total receivables	143,823	21,456	(62,592)	102,687
Prepaid expenses and other assets	45,545	—	—	45,545
Total current assets	197,034	21,456	(62,592)	155,898
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,587,206	271,608	—	5,858,814
Furniture, fixtures and other	16,158	—	—	16,158
Total property and equipment	5,603,364	271,608	—	5,874,972
Less accumulated depreciation, depletion and amortization	4,149,960	90,109	—	4,240,069
Net property and equipment	1,453,404	181,499	—	1,634,903
Restricted deposits for asset retirement obligations	34,675	—	—	34,675
Deferred income tax	—	11,662	(11,662)	—
Other assets	345,143	212,655	(542,075)	15,723
Total assets	$2,030,256	$ 427,272	$(616,329)	$1,841,199
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 79,587	$ 1,410	$ —	$ 80,997
Undistributed oil and natural gas proceeds	34,355	351	—	34,706
Asset retirement obligations	128,584	—	—	128,584
Accrued liabilities	30,294	—	—	30,294
Income taxes	—	64,249	(62,592)	1,657
Deferred income taxes – current portion	5,293	—	—	5,293
Total current liabilities	278,113	66,010	(62,592)	281,531
Long-term debt	694,000	—	—	694,000
Asset retirement obligations, less current portion	233,704	31,843	—	265,547
Deferred income taxes	57,100	—	(11,662)	45,438
Other liabilities	221,342	—	(212,656)	8,686
Commitments and contingencies	—	—	—	—
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	383,966	231,759	(231,759)	383,966
Retained earnings	186,197	97,660	(97,660)	186,197
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	545,997	329,419	(329,419)	545,997
Total liabilities and shareholders' equity	$2,030,256	$ 427,272	$(616,329)	$1,841,199

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

Condensed Consolidating Balance Sheet as of December 31, 2010

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 28,655	$ —	$ —	$ 28,655
Receivables:				
Oil and natural gas sales	50,421	29,490	—	79,911
Joint interest and other	25,415	—	—	25,415
Insurance	1,014	—	—	1,014
Income taxes	2,492	—	(2,492)	—
Total receivables	79,342	29,490	(2,492)	106,340
Deferred income taxes	5,784	2,755	(2,755)	5,784
Prepaid expenses and other assets	23,426	—	—	23,426
Total current assets	137,207	32,245	(5,247)	164,205
Property and equipment – at cost:				
Oil and natural gas properties and equipment	4,955,460	270,122	—	5,225,582
Furniture, fixtures and other	15,841	—	—	15,841
Total property and equipment	4,971,301	270,122	—	5,241,423
Less accumulated depreciation, depletion and amortization	3,994,085	27,310	—	4,021,395
Net property and equipment	977,216	242,812	—	1,220,028
Restricted deposits for asset retirement obligations	30,636	—	—	30,636
Deferred income taxes	2,819	—	—	2,819
Other assets	275,461	47,160	(316,215)	6,406
Total assets	$1,423,339	$ 322,217	$(321,462)	$1,424,094
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 77,422	$ 3,020	$ —	$ 80,442
Undistributed oil and natural gas proceeds	24,866	374	—	25,240
Asset retirement obligations	92,575	—	—	92,575
Accrued liabilities	25,827	—	—	25,827
Income taxes	—	20,044	(2,492)	17,552
Total current liabilities	220,690	23,438	(2,492)	241,636
Long-term debt	450,000	—	—	450,000
Asset retirement obligations, less current portion	269,016	29,725	—	298,741
Deferred income taxes	2,755	—	(2,755)	—
Other liabilities	59,135	—	(47,161)	11,974
Commitments and contingencies	—	—	—	—
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	377,529	236,944	(236,944)	377,529
Retained earnings	68,380	32,110	(32,110)	68,380
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	421,743	269,054	(269,054)	421,743
Total liabilities and shareholders' equity	$1,423,339	$ 322,217	$(321,462)	$1,424,094

Table of Contents

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

Condensed Consolidating Statement of Income for the Three Months Ended September 30, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$174,935	$ 70,436	$ —	$ 245,371
Operating costs and expenses:				
Lease operating expenses	49,854	9,045	—	58,899
Production taxes	1,050	—	—	1,050
Gathering and transportation	3,669	1,184	—	4,853
Depreciation, depletion and amortization	55,679	21,377	—	77,056
Asset retirement obligation accretion	6,693	706	—	7,399
General and administrative expenses	18,104	—	—	18,104
Derivative (gain)	(17,323)	—	—	(17,323)
Total costs and expenses	117,726	32,312	—	150,038
Operating income	57,209	38,124	—	95,333
Earnings of affiliates	24,780	—	(24,780)	—
Interest expense:				
Incurred	14,721	—	—	14,721
Capitalized	(3,163)	—	—	(3,163)
Loss on extinguishment of debt	2,031	—	—	2,031
Interest income	6	—	—	6
Income before income tax expense	68,406	38,124	(24,780)	81,750
Income tax expense	15,478	13,344	—	28,822
Net income	$ 52,928	$ 24,780	$ (24,780)	$ 52,928

Condensed Consolidating Statement of Income for the Nine Months Ended September 30, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$507,689	$ 201,459	$ —	$ 709,148
Operating costs and expenses:				
Lease operating expenses	130,001	29,900	—	159,901
Production taxes	2,183	—	—	2,183
Gathering and transportation	9,990	3,213	—	13,203
Depreciation, depletion and amortization	155,874	62,800	—	218,674
Asset retirement obligation accretion	21,125	2,118	—	23,243
General and administrative expenses	51,653	2,582	—	54,235
Derivative (gain)	(10,815)	—	—	(10,815)
Total costs and expenses	360,011	100,613	—	460,624
Operating income	147,678	100,846	—	248,524
Earnings of affiliates	65,550	—	(65,550)	—
Interest expense:				
Incurred	36,913	—	—	36,913
Capitalized	(6,654)	—	—	(6,654)
Loss on extinguishment of debt	22,694	—	—	22,694
Interest income	22	—	—	22
Income before income tax expense	160,297	100,846	(65,550)	195,593
Income tax expense	33,545	35,296	—	68,841
Net income	$126,752	$ 65,550	$ (65,550)	$ 126,752

Table of Contents

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

Condensed Consolidating Statement of Income for the Three Months Ended September 30, 2010

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$140,410	$ 29,165	$ —	$ 169,575
Operating costs and expenses:				
Lease operating expenses	31,091	3,280	—	34,371
Production taxes	276	—	—	276
Gathering and transportation	4,225	382	—	4,607
Depreciation, depletion and amortization	59,756	9,295	—	69,051
Asset retirement obligation accretion	6,119	145	—	6,264
General and administrative expenses	13,389	—	—	13,389
Derivative loss	4,770	—	—	4,770
Total costs and expenses	119,626	13,102	—	132,728
Operating income	20,784	16,063	—	36,847
Earnings of affiliates	10,441	—	(10,441)	—
Interest expense:				
Incurred	10,485	—	—	10,485
Capitalized	(1,345)	—	—	(1,345)
Interest income	150	—	—	150
Income before income tax expense	22,235	16,063	(10,441)	27,857
Income tax expense (benefit)	(4,953)	5,622	—	669
Net income	$ 27,188	$ 10,441	$ (10,441)	$ 27,188

Condensed Consolidating Statement of Income for the Nine Months Ended September 30, 2010

	Parent Company	Guarantor Subsidiaries (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$470,506	$ 48,321	$ —	$ 518,827
Operating costs and expenses:				
Lease operating expenses	113,004	9,190	—	122,194
Production taxes	788	—	—	788
Gathering and transportation	12,324	596	—	12,920
Depreciation, depletion and amortization	186,511	15,359	—	201,870
Asset retirement obligation accretion	18,435	241	—	18,676
General and administrative expenses	36,870	1,273	—	38,143
Derivative (gain)	(8,500)	—	—	(8,500)
Total costs and expenses	359,432	26,659	—	386,091
Operating income	111,074	21,662	—	132,736
Earnings of affiliates	14,080	—	(14,080)	—
Interest expense:				
Incurred	32,319	—	—	32,319
Capitalized	(4,090)	—	—	(4,090)
Interest income	632	—	—	632
Income before income tax expense	97,557	21,662	(14,080)	105,139
Income tax expense	184	7,582	—	7,766
Net income	$ 97,373	$ 14,080	$ (14,080)	$ 97,373

(1) Began operations on May 1, 2010. Includes only May 2010 to September 2010 activity.

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

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 126,752	$ 65,550	$ (65,550)	$ 126,752
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	176,999	64,918	—	241,917
Amortization of debt issuance costs	1,401	—	—	1,401
Loss on extinguishment of debt	22,694	—	—	22,694
Share-based compensation	6,437	—	—	6,437
Derivative (gain)	(10,815)	—	—	(10,815)
Cash payments on derivative settlements	(9,239)	—	—	(9,239)
Deferred income taxes	68,350	(8,908)	—	59,442
Earnings of affiliates	(65,550)	—	65,550	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(10,946)	8,033	—	(2,913)
Joint interest and other receivables	7,465	—	—	7,465
Insurance receivables	18,971	—	—	18,971
Income taxes	(60,099)	44,205	—	(15,894)
Prepaid expenses and other assets	(22,796)	(165,495)	165,690	(22,601)
Asset retirement obligations	(51,349)	—	—	(51,349)
Accounts payable and accrued liabilities	25,717	(1,631)	(194)	23,892
Other liabilities	165,387	—	(165,496)	(109)
Net cash provided by operating activities	389,379	6,672	—	396,051
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(434,582)	—	—	(434,582)
Investment in oil and natural gas properties and equipment	(183,735)	(1,487)	—	(185,222)
Investment in subsidiary	5,185	—	(5,185)	—
Proceeds from sales of oil and natural gas properties and equipment	15	—	—	15
Purchases of furniture, fixtures and other	(318)	—	—	(318)
Net cash used in investing activities	(613,435)	(1,487)	(5,185)	(620,107)
Financing activities:				
Issuance of 8.5% Senior Notes	600,000	—	—	600,000
Repurchase of 8.25% Senior Notes	(450,000)	—	—	(450,000)
Borrowings of long-term debt – revolving bank credit facility	512,000	—	—	512,000
Repayments of long-term debt – revolving bank credit facility	(418,000)	—	—	(418,000)
Repurchase premium and debt issuance costs	(31,997)	—	—	(31,997)
Investment from parent	—	(5,185)	5,185	—
Dividends to shareholders	(8,936)	—	—	(8,936)
Net cash provided by (used in) financing activities	203,067	(5,185)	5,185	203,067
(Decrease) in cash and cash equivalents	(20,989)	—	—	(20,989)
Cash and cash equivalents, beginning of period	28,655	—	—	28,655
Cash and cash equivalents, end of period	$ 7,666	$ —	$ —	$ 7,666

Table of Contents

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

Condensed Consolidating Statement of Cash Flows for the Nine Months Ended September 30, 2010

	Parent Company	Guarantor Subsidiaries (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 97,373	$ 14,080	$ (14,080)	$ 97,373
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	204,946	15,600	—	220,546
Amortization of debt issuance costs	1,004	—	—	1,004
Share-based compensation	3,576	—	—	3,576
Derivative (gain)	(8,500)	—	—	(8,500)
Cash payments on derivative settlements	(410)	—	—	(410)
Deferred income taxes	4,253	2,230	—	6,483
Earnings of affiliates	(14,080)	—	14,080	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	12,941	(9,311)	—	3,630
Joint interest and other receivables	29,542	—	—	29,542
Insurance receivables	36,763	—	—	36,763
Income taxes	78,801	5,351	—	84,152
Prepaid expenses and other assets	(1,464)	(29,448)	29,448	(1,464)
Asset retirement obligations	(62,620)	—	—	(62,620)
Accounts payable and accrued liabilities	(32,632)	2,484	—	(30,148)
Other liabilities	42,398	—	(29,448)	12,950
Net cash provided by operating activities	391,891	986	—	392,877
Investing activities:				
Acquisition property interests in oil and natural gas properties	—	(116,589)	—	(116,589)
Investment in oil and natural gas properties and equipment	(126,441)	(986)	—	(127,427)
Proceeds from sales of oil and natural gas properties and equipment	1,335	—	—	1,335
Investment in subsidiary	(116,589)	—	116,589	—
Purchases of furniture, fixtures and other	(405)	—	—	(405)
Net cash used in investing activities	(242,100)	(117,575)	116,589	(243,086)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	427,500	—	—	427,500
Repayments of long-term debt – revolving bank credit facility	(427,500)	—	—	(427,500)
Dividends to shareholders	(7,467)	—	—	(7,467)
Investment from parent	—	116,589	(116,589)	—
Net cash provided by (used in) financing activities	(7,467)	116,589	(116,589)	(7,467)
Increase in cash and cash equivalents	142,324	—	—	142,324
Cash and cash equivalents, beginning of period	38,187	—	—	38,187
Cash and cash equivalents, end of period	$ 180,511	$ —	$ —	$ 180,511

(1) Began operations on May 1, 2010. Includes only May 2010 to September 2010 activity.

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 Exchange Act, that 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. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A "Risk Factors" and Item 7A "Quantitative and Qualitative Disclosures About Market Risk" of our Annual Report on Form 10-K for the year ended December 31, 2010 and may be discussed or updated from time to time in subsequent reports filed with the SEC. 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 focused primarily in the Gulf of Mexico and onshore Texas. We have grown through acquisitions, exploitation and exploration and currently hold working interests in approximately 67 producing properties or fields capable of production in federal and state waters. The majority of our daily production is currently derived from offshore wells we operate. In May 2011, we closed on the acquisition of the Permian Basin Properties as described below. After completing this acquisition and acquiring other leasehold interests, we now hold working interests in over 173,000 net acres onshore in Texas. Acquiring these onshore properties has diversified our business by having both significant offshore and onshore operations.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil and natural gas production and the price that we receive for such production. Our production volumes for the first nine months of 2011 was comprised of approximately 47% oil, condensate and natural gas liquids and 53% natural gas, determined using the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per one thousand cubic feet equivalent ("Mcfe") for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. For example, for the first nine months of 2011, our average realized price for oil and NGLs on a Mcfe basis was $15.51 compared to $4.34 per Mcf for natural gas. For the first nine months of 2011, our combined total production of oil, condensate, natural gas liquids and natural gas was approximately 14.9% higher on a Mcfe basis than during the same period in 2010.

During August 2011, we completed the acquisition of Shell's 64.3% interest in the Fairway Field along with a like interest in the associated Yellowhammer gas processing plant, with an effective date of September 1, 2010. Estimates of proved reserves as of June 30, 2011 were 54.5 billion cubic feet equivalent ("Bcfe"). The adjusted purchase price was comprised of $40.0 million of cash, which was funded through borrowings under our revolving bank credit facility, and we assumed the ARO associated with the properties and plant which we have currently estimated to be $7.8 million. We are finalizing our assessment of the fair values of the assets acquired and liabilities assumed. Therefore, the purchase price allocation is preliminary and is subject to change.

During May 2011, we completed the acquisition of approximately 21,900 gross acres (21,500 net acres) of oil and gas leasehold interests in the Permian Basin Properties from Opal. Including adjustments from an effective date of January 1, 2011, the adjusted purchase price was $397.1 million. Although further adjustments could occur to the purchase price, no further adjustments are expected at this time. We acquired estimated proved reserves of approximately 30 million barrels of oil equivalent (182 Bcfe) (using a 6 to 1 Mcf to barrel equivalency) as of December 31, 2010, comprised of approximately 91% oil and natural gas liquids and which are approximately 78% proved undeveloped. Capital expenditures associated with planned development activities for these properties from the closing date of May 11, 2011 to December 31, 2011 are currently estimated to be between $70 million and $80 million. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

During 2010, we closed on two major acquisitions. In April 2010, we acquired two deepwater properties from Total and in November 2010, we acquired three deepwater fields from Shell. These transactions are described in *Financial Statements - Note 2 – Acquisitions* under Part I, Item 1 of this Form 10-Q.

The third-party pipeline used by our Main Pass 108, 98 and 180 fields, which had been offline since June 2010, became operational on March 31, 2011. In the second quarter of 2011, we continued to increase production in this area. In September 2011, these fields produced approximately 44 MMcfe per day, made up of 33,083 Mcf of natural gas and 1,834 barrels of oil/NGLs per day.

Prices for oil have continued to be volatile in 2011. For the nine months ended September 30, 2011, our average realized sales price for oil and NGLs (unhedged) increased significantly over the comparable period in 2010. The majority of our oil production is priced using the posted spot price for West Texas Intermediate ("WTI") as a base price plus a premium depending on the type of crude oil. WTI is frequently used to value domestically produced crude oil. Our offshore oil production, which is comprised of various crudes including Light Louisiana Sweet, Heavy Louisiana Sweet and Poseidon, started selling at a significant premium relative to WTI earlier this year. In 2011 compared to 2010, our realized oil sales price increased 33.5%, compared to a 22.8% increase in the posted spot price for WTI. Our crudes have better reflected the international oil market prices, as measured using Brent crude, which increased 44.6% for this time frame. Oil prices continue to be impacted by market fundamentals such as supply and demand and also by political events and disruptions throughout the world, including events in Greece, Japan, Africa and the Middle East. Long-term forecasts for oil demand, and therefore global oil prices, continue to be favorable in several key growing markets, specifically China and India.

The premiums received on our offshore oil production have been up to $24.00 per barrel for the nine months ended September 30, 2011. In comparison, the average premium spread between Light Louisiana Sweet crude and WTI crude was approximately $3.00 per barrel during 2010. We may continue to experience higher premiums to WTI crude in our future sales of offshore crude oil until such time as the causative factors are resolved. We cannot predict with any certainty how long such pricing conditions will last.

Natural gas prices are much more affected by domestic issues, such as supply, local demand issues and domestic economic conditions. The Henry Hub posted spot price for natural gas was $4.22 per MMBtu for the nine months ended September 30, 2011 representing a decrease of 7.5% from $4.56 per MMBtu for the same period in 2010. The price for natural gas in the nine months ended September 30, 2011 ranged from a low of $3.68 per MMBtu to a high of $4.92 per MMBtu and the range in the same period of 2010 was from $3.72 to $7.51 per MMBtu. During the nine months ended September 30, 2011, the average realized sales price of our natural gas (unhedged) decreased 8.6% from the comparable period of 2010. We are expecting continued weakness in natural gas prices unless demand for natural gas increases as a result of a strong economic recovery, drilling activity subsides dramatically or forced production shut-ins occur. There is also a risk that, as a result of successful exploration and development activities in the shale areas coupled with the availability of increasing amounts of liquefied natural gas, increased supplies of natural gas will offset or mitigate the impact of any natural gas shut-ins or demand increases resulting from improved economic conditions. According to industry sources, the rig count for horizontal drilling rigs, used primarily in the shale formation areas such as Louisiana, Arkansas, Texas, North Dakota and Pennsylvania, has reached or exceeded record levels. Further, such sources indicate that onshore natural gas producers have continued to drill in attempts to yield production sufficient to preserve existing leases. Seasonal weather conditions also impact the demand for and price of natural gas.

Revenue from our offshore production is highly dependent on pipelines owned by others to access markets for our products. To the extent that the price such pipelines charge us increases, our revenues from the sales of our products would go down or transportation costs would increase, the result of either would be a reduction in operating income. Certain pipelines have filed tariffs to increase the amounts they charge us and we believe that we have limited alternatives to use other pipelines.

Should prices decline for oil and natural gas in the future, it would negatively impact our future oil 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, create issues with financial ratio compliance, and result in a reduction of the borrowing base associated with our credit agreement, depending on the severity of such declines. If those 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.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in the deep water of the Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced economic, environmental and natural resource damage in the Gulf Coast region. In response to the explosion and spill, the Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEMRE") issued a series of “Notices to Lessees” (“NTLs”), and other significant changes in regulations. In addition, the BOEMRE implemented a six-month moratorium on drilling activities which began in May 2010. There also continue to be many proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and spill. After the moratorium ended in 2010, it was not until March 2011 that deep water drilling permits began to be issued, and even then only sporadically, to continue drilling activities that had commenced prior to the Deepwater Horizon incident. Since March 2011, deepwater drilling permits have been issued, albeit at the slower and more measured pace than before the Deepwater Horizon event. The most significant regulatory changes since the Deepwater Horizon event are regulations related to assessing the potential environmental impact of future spills using worse case discharge scenarios on a well-by-well basis, 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 it takes to obtain drilling permits and increases the cost of operations. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time. The permitting process is also slow and inconsistent for shallow water work and even for plug and abandonment activities. This could lead to increased costs and performing work at less than optimal effectiveness. We have not experienced delays in obtaining permits related to our onshore operations.

In October 2011, the BOEMRE was split into three separate entities: the Office of National Resources Revenue (“ONRR”), which assumed the functions of the Minerals Revenue Management Program; the Bureau of Ocean Energy Management (“BOEM”), which is responsible for managing development of the nation’s offshore resources in an environmentally and economically responsible way; and the Bureau of Safety and Environmental Enforcement (“BSEE”), which is responsible for enforcement of safety and environmental regulations.

Table of Contents

Results of Operations

The following table sets forth selected financial data for the periods indicated (all values are net to our interest unless indicated otherwise):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
	(In thousands, except percentages and per share data)							
Financial:								
Revenues:								
Oil and NGLs	$183,969	$126,325	$ 57,644	45.6%	$537,400	$366,567	$170,833	46.6%
Natural gas	61,174	47,236	13,938	29.5%	170,753	156,025	14,728	9.4%
Other	228	(3,986)	4,214	NM	995	(3,765)	4,760	NM
Total revenues	245,371	169,575	75,796	44.7%	709,148	518,827	190,321	36.7%
Operating costs and expenses:								
Lease operating expenses	58,899	34,371	24,528	71.4%	159,901	122,194	37,707	30.9%
Production taxes	1,050	276	774	280.4%	2,183	788	1,395	177.0%
Gathering and transportation	4,853	4,607	246	5.3%	13,203	12,920	283	2.2%
Depreciation, depletion, amortization and accretion	84,455	75,315	9,140	12.1%	241,917	220,546	21,371	9.7%
General and administrative expenses	18,104	13,389	4,715	35.2%	54,235	38,143	16,092	42.2%
Derivative (gain) loss	(17,323)	4,770	(22,093)	NM	(10,815)	(8,500)	(2,315)	27.2%
Total costs and expenses	150,038	132,728	17,310	13.0%	460,624	386,091	74,533	19.3%
Operating income	95,333	36,847	58,486	158.7%	248,524	132,736	115,788	87.2%
Interest expense, net of amounts capitalized	11,558	9,140	2,418	26.5%	30,259	28,229	2,030	7.2%
Loss on extinguishment of debt (1)	2,031	—	2,031	NM	22,694	—	22,694	NM
Interest income	6	150	(144)	(96.0%)	22	632	(610)	(96.5%)
Income before income tax expense	81,750	27,857	53,893	193.5%	195,593	105,139	90,454	86.0%
Income tax expense	28,822	669	28,153	NM	68,841	7,766	61,075	786.4%
Net income	$ 52,928	$ 27,188	$ 25,740	94.7%	$126,752	$ 97,373	$ 29,379	30.2%
Basic and diluted earnings per common share	$ 0.70	$ 0.36	$ 0.34	94.4%	$ 1.68	$ 1.30	$ 0.38	29.2%

(1) In June 2011 and July 2011, we repurchased the entire $450 million outstanding of our 8.25% Senior Notes, which resulted in a loss on extinguishment of debt of $2.0 million and $22.0 million for the three and nine months ended September 30, 2011, respectively. In May 2011, we entered into the Fourth Amended and Restated Credit Agreement, which replaced the Prior Credit Agreement. Unamortized debt issuance costs of $0.7 million related to the Prior Credit Agreement were expensed for the nine months ended September 30, 2011. For additional information about our revolving bank credit facility and long-term debt, refer to *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

NM = percentage change not meaningful

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
Operating:								
Net sales:								
Natural gas (Bcf)	14.3	10.6	3.7	34.9%	39.4	32.9	6.5	19.8%
Oil and NGLs (MMBbls)	2.0	1.8	0.2	11.1%	5.8	5.3	0.5	9.4%
Total natural gas and oil (Bcfe) (1)	26.5	21.6	4.9	22.7%	74.0	64.4	9.6	14.9%
Total natural gas and oil (MMBoe) (1)	4.4	3.6	0.8	22.2%	12.3	10.7	1.6	15.0%
Average daily equivalent sales (MMcfe/d)	287.9	235.3	52.6	22.4%	271.2	235.9	35.3	15.0%
Average realized sales prices (Unhedged):								
Natural gas ($/Mcf)	$ 4.27	$ 4.47	$ (0.20)	(4.5%)	$ 4.34	$ 4.75	$ (0.41)	(8.6%)
Oil and NGLs($/Bbl)	90.84	68.35	22.49	32.9%	93.08	69.73	23.35	33.5%
Natural gas equivalent ($/Mcfe)	9.26	8.02	1.24	15.5%	9.57	8.12	1.45	17.9%
Average realized sales prices (Hedged):								
Natural gas ($/Mcf)	$ 4.27	$ 4.58	$ (0.31)	(6.8%)	$ 4.34	$ 4.91	$ (0.57)	(11.6%)
Oil and NGLs ($/Bbl)	90.39	68.35	22.04	32.2%	91.48	69.55	21.93	31.5%
Natural gas equivalent ($/Mcfe)	9.22	8.07	1.15	14.3%	9.44	8.18	1.26	15.4%
Average per Mcfe ($/Mcfe):								
Lease operating expenses	$ 2.22	$ 1.59	$ 0.63	39.6%	$ 2.16	$ 1.90	$ 0.26	13.7%
Gathering and transportation	0.18	0.21	(0.03)	(14.3%)	0.18	0.20	(0.02)	(10.0%)
Production costs	2.40	1.80	0.60	33.3%	2.34	2.10	0.24	11.4%
Production taxes	0.04	0.01	0.03	300.0%	0.03	0.01	0.02	200.0%
Depreciation, depletion, amortization and accretion	3.19	3.48	(0.29)	(8.3%)	3.27	3.42	(0.15)	(4.4%)
General and administrative expenses	0.68	0.62	0.06	9.7%	0.73	0.59	0.14	23.7%
	$ 6.31	$ 5.91	$ 0.40	6.8%	$ 6.37	$ 6.12	$ 0.25	4.1%
Total number of offshore wells drilled (gross)	1	—	1	NM	4	5	(1)	(20.0%)
Total number of onshore wells drilled (gross)	21	2	19	NM	31	2	29	NM
Total number of offshore productive wells drilled (gross)	1	—	1	NM	4	4	—	(0.0%)
Total number of onshore productive wells drilled (gross)	20	—	20	NM	30	—	30	NM

(1) The conversion to cubic feet equivalent and barrels of equivalent measures determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

NM = percentage change not meaningful

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010

Revenues. Total revenues increased $75.8 million, or 44.7%, to $245.4 million for the three months ended September 30, 2011, as compared to the same period in 2010. Oil and NGL revenues increased $57.6 million, natural gas revenues increased $13.9 million and other revenues increased $4.3 million. The oil and NGL revenue increase was attributable to a 32.9% increase in the average realized sales price to $90.84 per barrel for the three months ended September 30, 2011 from $68.35 per barrel for the same period in 2010, combined with an increase of 11.1% in sales volumes. The sales volume increase for oil and NGL is primarily attributable to increases associated with properties acquired in 2011 and 2010. The increase in natural gas revenue resulted from a 34.9% increase in sales volumes, partially offset by a 4.5% decrease in the average realized natural gas sales price. For the three months ended September 30, 2011, the natural gas average realized sales price was $4.27 per Mcf compared to $4.47 per Mcf for the same period in 2010. The sales volume increase for natural gas is primarily attributable to increases associated with our acquisition activities, the Main Pass 108 fields resuming production and successful exploration efforts. Other revenue changed primarily due to a disallowance of $4.7 million by the BOEMRE of royalty relief for transportation of deepwater production through our subsea pipeline system that was recorded in the three months ended September 30, 2010.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, increased $24.5 million to $58.9 million for the three months ended September 30, 2011 compared to the same period in 2010. On a per Mcfe basis, lease operating expenses increased to $2.22 per Mcfe during the three months ended September 30, 2011 compared to $1.59 per Mcfe during the same period in 2010. On a component basis, base lease operating expenses, hurricane remediation costs net of insurance claims, workover costs, insurance premiums and facility expenses increased $10.1 million, $6.6 million, $4.3 million, $2.1 million and $1.4 million, respectively. The increase in base lease operating expenses is primarily attributable to expenses associated with the properties acquired in 2011 and 2010, higher costs at our various non-operated properties, increased processing fees associated with our Daniel Boone field production and expenses billed to a third party in 2010 related to a divestiture that did not occur in 2011. Hurricane remediation costs net of insurance claims increased due to higher reimbursements received in the 2010 period. Workover costs increased primarily due to work performed at our new Permian Basin Properties. The increase in insurance premiums resulted primarily from higher premiums on our insurance policies covering well control and hurricane damage which incorporates additional acquired properties. The increase in facility expenses is primarily attributable to work performed at the Fairway Properties.

Production taxes. Production taxes increased to $1.1 million for the three months ended September 30, 2011 compared to $0.3 million in the prior year primarily due to the Permian Basin Properties operations and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs were basically flat for the quarter compared to the prior year.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $3.19 per Mcfe for the three months ended September 30, 2011 from $3.48 per Mcfe in the prior year. On a nominal basis, DD&A increased to $84.5 million for the three months ended September, 2011 from $75.3 million in the prior year. The decrease to DD&A on a per Mcfe basis was primarily due to increases in proved reserves while DD&A on a nominal basis increased due to higher production volumes.

General and administrative expenses ("G&A"). G&A expenses increased to $18.1 million for the three months ended September 30, 2011 from $13.4 million for the prior year primarily due to higher incentive compensation as a result of improved financial and operational performance, and expanded activities onshore and offshore. In addition, costs associated with acquisition activities, transition service fees paid to the sellers of the acquired properties, litigation settlements and accruals and increased professional fees resulted in higher G&A. On a per Mcfe basis, G&A was $0.68 per Mcfe for the three months ended September 30, 2011, compared to $0.62 per Mcfe for the same period in 2010.

Derivative (gain)/loss. For the three months ended September 30, 2011, our derivative gain of $17.3 million related to a change in the fair value of our commodity derivatives as a result of changes in crude oil prices. For the comparable period of 2010, our derivative loss of $4.8 million related to a loss from our commodity derivatives as a result of changes in crude oil and natural gas prices. For additional details about our derivatives, refer to *Financial Statements – Note 5 – Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

Interest expense. Interest expense incurred increased to $14.7 million for the three months ended September 30, 2011 from $10.5 million for the same period in 2010. During 2011, the amounts outstanding for our senior notes increased to $600 million from $450 million and the senior note annual interest rate increased to 8.5% from 8.25%. In addition, average borrowings on our revolving bank credit facility increased. During the three months ended September 30 of 2011 and 2010, $3.2 million and $1.3 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties which increased with the Permian Basin Properties acquisition. For additional information about our long-term debt and revolving bank credit facility, refer to *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

Loss on extinguishment of debt. The loss on extinguishment of debt of $2.0 million was attributable to the redemption of the remaining outstanding balance of $43.9 million of the 8.25% Senior Notes. The amount expensed included the call premium paid to the remaining note holders pursuant to the terms of the note and to write off the balance of unamortized debt issuance costs related to the 8.25% Senior Notes. 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.

Income tax expense. Income tax expense increased to $28.8 million for the three months ended September 30, 2011 compared to $0.7 million for the same period of 2010. Our effective tax rate for the three months ended September 30, 2011 was 35.3%, which approximates the federal and state statutory rates. Our effective tax rate for the three months ended September 30, 2010 was 2.4% and primarily reflects a reduction in our valuation allowance that was recorded in prior years.

Nine Months Ended September 30, 2011 Compared to the Nine Months Ended September 30, 2010

Revenues. Total revenues increased $190.3 million, or 36.7%, to $709.1 million for the nine months ended September 30, 2011, as compared to the same period in 2010. Oil and NGL revenues increased $170.8 million, natural gas revenues increased $14.7 million and other revenues increased $4.8 million. The oil and NGL revenue increase was attributable to a 33.5% increase in the average realized sales price to $93.08 per barrel for the nine months ended September 30, 2011 from $69.73 per barrel for the same period in 2010, combined with an increase of 9.4% in sales volumes. The sales volume increase for oil and NGL is primarily attributable to increases associated with properties acquired in 2011 and 2010. The increase in natural gas revenue resulted from a 19.8% increase in sales volumes, partially offset by an 8.6% decrease in the average realized natural gas sales price to $4.34 per Mcf for the nine months ended September 30, 2011 from $4.75 per Mcf for the same period in 2010. The sales volume increase for natural gas is primarily attributable to increases associated with our acquisition activities, the Main Pass 108 fields resuming production and successful exploration efforts. Other revenue changed primarily due to a disallowance of $4.7 million by the BOEMRE of royalty relief for transportation of deepwater production through our subsea pipeline system that was recorded in the three months ended September 30, 2010.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, increased $37.7 million to $159.9 million in the nine months ended September 30, 2011 compared to the same period in 2010. On a per Mcfe basis, lease operating expenses increased to $2.16 per Mcfe during the nine months ended September 30, 2011 compared to $1.90 per Mcfe during the same period of 2010. On a component basis, base lease operating expenses, hurricane remediation costs net of insurance claims, facility expenses and workover costs increased $15.3 million, $11.5 million, $11.0 million, and $2.3 million, respectively. As a partial offset, insurance premiums decreased $2.5 million. The increase in base lease operating expenses is primarily attributable to expenses associated with the properties acquired in 2011 and 2010, higher costs at our various non-operated properties, increased processing fees associated with our Daniel Boone field production and expenses billed to a third party in 2010 related to a divestiture that did not occur in 2011. Hurricane remediation costs net of insurance claims increased primarily due to higher reimbursements received in the 2010 period. The increase in facility expenses is primarily attributable to work performed on the tendon tension monitoring system and mechanical repairs at our Matterhorn platform, the pipeline repairs at our Ship Shoal 300 field to remove paraffin and inspection fees at our Main Pass 252 platforms. Workover costs increased due to work performed at our new Permian Basin Properties and expenses at the Main Pass 108 field, partially offset by projects in 2010 that did not occur in 2011. The decrease in insurance premiums resulted primarily from lower premiums on our insurance policies covering well control and hurricane damage that cover the policy period June 1, 2010 to June 1, 2011. Our premiums increased effective with the June 1, 2011 renewal.

Production taxes. Production taxes increased to $2.2 million for the nine months ended September 30, 2011 compared to $0.8 million in the same period of 2010 primarily due to the Permian Basin Properties operations and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs were basically flat for the nine months ended September 30, 2011 compared to the same period in 2010.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $3.27 per Mcfe for the nine months ended September 30, 2011 from $3.42 per Mcfe for the same period in 2010. On a nominal basis, DD&A increased to $241.9 million for the nine months ended September 30, 2011 from $220.5 million in the same period in 2010. The decrease to DD&A on a per Mcfe basis was primarily due to increases in proved reserves while DD&A on a nominal basis increased due to higher production volumes.

General and administrative expenses. General and administrative expenses increased to $54.2 million for the nine months ended September 30, 2011 from $38.1 million for the same period in 2010, primarily due to higher incentive compensation as a result of improved financial and operational performance, and expanded activities onshore and offshore. In addition, costs associated with acquisition activities, surety premiums, transition service fees paid to the sellers of the acquired properties, and litigation settlements and accruals resulted in higher G&A. Also, there were administration fees earned in 2010 related to an asset disposition and no such fees were earned in 2011. On a per Mcfe basis, G&A was $0.73 per Mcfe for the nine months ended September 30, 2011, compared to $0.59 per Mcfe for the same period in 2010.

Derivative (gain)/loss. For the nine months ended September 30, 2011, our derivative gain of $10.8 million related entirely to a change in the fair value of our commodity derivatives as a result of the changes in crude oil prices. For the nine months ended September 30, 2010, our derivative gain of $8.5 million related to a gain from our commodity derivatives of $8.8 million and a loss of $0.3 million related to our interest rate swap. For additional details about our derivatives, refer to Item 1 *Financial Statements – Note 5 – Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

Interest expense. Interest expense incurred increased to $36.9 million for the nine months ended September 30, 2011 from $32.3 million for the same period in 2010. During 2011, the amounts outstanding for our senior notes increased to $600 million from $450 million and the senior note annual interest rate increased to 8.5% from 8.25%. During the nine months ended September 30 of 2011 and 2010, $6.7 million and $4.1 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties which increased with the Permian Basin Properties acquisition. For additional information about our long-term debt and revolving bank credit facility, refer to *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

Loss on extinguishment of debt. The loss on extinguishment of debt of $22.7 million was attributable primarily to the repurchase of the $450 million outstanding of our 8.25% Senior Notes. The repurchase of the 8.25% Senior Notes was funded with a portion of the proceeds from the issuance of the 8.5% Senior Notes. The call premiums, unamortized debt issuance costs and other related expenses totaled $22.0 million. In addition, the previous revolving bank credit facility was replaced resulting in the write off of unamortized debt issuance costs of $0.7 million. For additional information about our long-term debt and revolving bank credit facility, refer to *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

Income tax expense. Income tax expense increased to $68.8 million for the nine months ended September 30, 2011 compared to $7.8 million for the same period of 2010. Our effective tax rate for the nine months ended September 30, 2011 was 35.2%, which approximates the federal and state statutory rates. Our effective tax rate for the nine months ended September 30, 2010 was 7.4% and primarily reflects a reduction in our valuation allowance that was recorded in 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. We have funded our capital expenditures, including acquisitions, with cash on hand, cash provided by operations, 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, 2011 was $396.1 million, compared to $392.9 million for the same period in 2010. The 2010 period included income tax refunds of $99.8 million primarily related to the Worker, Homeowner and Business Assistance Act of 2009 that allowed us to carry back losses to previously closed years, while the 2011 period included tax payments of $25.3 million. Otherwise, cash flow from operating activities increased $128 million due to substantially improved operating results. Our combined average realized sales price was 17.9% higher than the comparable 2010 period and our combined total production of oil, NGLs and natural gas during the nine months ended September 30, 2011 was 14.9% higher than the comparable 2010 period.

Net cash used in investing activities during the nine months ended September 30, 2011 and 2010 were $620.1 million and $243.1 million, respectively, which primarily represents our investments in oil and natural gas properties. Major acquisitions consisted of the cash portion of the Permian Basin Properties ($394.6 million) and the Fairway Properties ($40.0 million) purchased in 2011 and the Matterhorn/Virgo Properties ($116.6 million) purchased in 2010. In addition, investments in other oil and natural gas properties and equipment were $185.2 million in the nine months ended September 30, 2011 compared to $127.4 million in the nine months ended September 30, 2010 with the increase primarily related to the Permian Basin Properties. There were minimal proceeds from sales of assets in the nine months ended September 30, 2011 and proceeds from asset sales were $1.3 million for the same period in 2010.

Net cash provided by financing activities was $203.1 million during the nine months ended September 30, 2011. Funds were provided through net borrowings on the revolving bank credit facility of $94 million and issuance of $600 million of 8.5% Senior Notes and partially offset by the repurchase of $450 million of the 8.25% Senior Notes, repurchase premium and debt issuance costs of $32.0 million and the payment of dividends of $8.9 million. See *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information on the senior notes transactions. Net cash used in financing activities during the nine months ended September 30, 2010 was $7.5 million which reflects dividend payments during the period.

At September 30, 2011, we had a cash balance of $7.7 million and $443.0 million of undrawn capacity available under the revolving bank credit facility which had a borrowing base of $537.5 million as of this date.

Credit agreement and long-term debt. At September 30, 2011, there was $94 million outstanding under our revolving bank credit facility compared to zero at December 31, 2010. At September 30, 2011, there was $600 million of our 8.5% Senior Notes outstanding and at December 31, 2010 there was $450 million outstanding of our 8.25% Senior Notes. 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.

On May 5, 2011, we entered into the Credit Agreement which provides a revolving bank credit facility with an initial borrowing base of $525 million collateralized by our oil and natural gas properties. The Credit Agreement terminates on May 5, 2015 and replaced the Prior Credit Agreement, which would have expired July 23, 2012. Fees and transactions costs related to the Credit Agreement were approximately $5.9 million. The terms of the Credit Agreement are substantially similar to the terms of the Prior Credit Agreement. Availability under the Credit Agreement is subject to a semi-annual borrowing base redetermination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the size of our revolving bank credit facility. The borrowing base was re-determined in October 2011 and was increased to $575 million.

The Credit Agreement contains various 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 as of September 30, 2011. During the nine months ended September 30, 2011, borrowings outstanding on the revolving bank credit facility increased to $300 million primarily to fund the acquisition of the Permian Basin Properties, which also included funding from cash on hand. These borrowings were subsequently reduced to $94 million as of September 30, 2011, primarily by utilizing funds received from the senior note transactions described below and net cash from operations, partially offset by capital expenditures. Letters of credit outstanding as of September 30, 2011 were $0.5 million.

On June 10, 2011, we issued $600 million of 8.5% Senior Notes and used a portion of the net proceeds to repurchase the $450 million outstanding of our 8.25% Senior Notes. The net cash provided by these senior notes transactions, which includes initial purchaser fees, redemption premiums and other transactions costs, was $123.9 million. These transactions extended the maturity date of our long-term debt and we used the net proceeds to pay down a portion of amounts outstanding under the revolving bank credit facility. The 8.5% Senior Notes mature on June 15, 2019. Interest is payable semi-annually in arrears on June 15 and December 15 of each year beginning on December 15, 2011. For additional information about our credit agreement and long-term debt, refer to *Financial Statements – Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

Derivatives. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of September 30, 2011, our outstanding derivative instruments consisted of commodity option contracts relating to approximately 0.4 MMBbls and 1.1 MMBbls of our anticipated oil production for the balance of 2011 and the full year of 2012, respectively. For additional details about our derivatives, refer to *Financial Statements – Note 5– Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

Hurricane Remediation and Insurance Claims. During the third quarter of 2008, Hurricane Ike, and to a much lesser extent Hurricane Gustav, caused property damage and disruptions to our exploration and production activities. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10 million per occurrence. In 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. The damage we incurred as a result of Hurricane Gustav was below our retention amount.

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.

In the nine months ended September 30, 2011 and 2010, we received cash of $18.9 million and $46.9 million, respectively, from our insurance carrier related to Hurricane Ike claims. We have recorded $1.7 million receivables as of September 30, 2011 for claims submitted and approved for payment as of this date. As of September 30, 2011, we have recorded in ARO an estimate of $57.1 million for additional costs to be incurred related to Hurricane Ike and we estimate that this work will be completed by the end of 2013. We expect to receive reimbursement for a portion of these costs from our insurance carrier once the costs are incurred, claims are processed and payments are approved, but cannot estimate the amount of reimbursement to be received at this time. Should necessary expenditures exceed our insurance coverage for damages incurred as a result of Hurricane Ike, or claims are denied by our insurance carrier for other reasons, we expect that our available cash on hand, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet these future cash needs.

For a discussion of our hurricane remediation costs related to lease operating expenses incurred during the nine months ended September 30, 2011 and 2010, refer to *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* under Part I, Item 1 of this Form 10-Q. Lease operating expenses will be offset in future periods to the extent that these costs incurred are approved for payment under our insurance policies.

We currently carry three layers of insurance coverage for our operating activities in the Gulf of Mexico. The current policy limits for well control and hurricane damage (defined as named windstorm in our policies) are up to $100 million and $120 million, respectively, and the policies are effective until June 1, 2012. We carry an additional $100 million of well control coverage effective until June 1, 2012 on certain wells at our Mahogany, Matterhorn, Virgo, Tahoe and SE Tahoe fields. A retention amount of $5 million for well control events and $37.5 million per hurricane occurrence must be satisfied by us before we are indemnified for losses. Certain properties we have deemed as non-core are not covered for hurricane damage; however, properties representing approximately 96% of our present value of estimated future net revenues discounted at 10% ("PV-10") at December 31, 2010 are covered under our insurance policies for hurricane damage. Pollution causing a negative environmental impact is characterized as a covered component of each of the well control and hurricane sections of the policy.

Our general and excess liability policy, which is effective until May 1, 2012, provides for $250 million of liability coverage for bodily injury and property damage, including liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility ("OSFR") requirement under the Oil Pollution Act ("OPA"), we are required to evidence $150 million of financial responsibility to the BSEE. We qualify to self-insure for $35 million of this amount and the remaining $115 million is covered by insurance. We may only collect proceeds under this OSFR policy after our well control, hurricane damage and excess liability policies have been exhausted.

The premiums for the above policies were $30 million compared to $22 million for the policies that expired in May and June of 2011. 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 the 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 a claim, the insurance companies will not pay our claim. 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 and natural gas, acquisition opportunities, and the results of our exploration and development activities. The following table presents our capital expenditures for acquisitions, exploration, development and other leasehold costs:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in thousands)	
Acquisition of Permian Basin Properties	$ 394,594	$ —
Acquisition of Fairway Properties	39,988	—
Acquisition of Matterhorn/Virgo Properties	—	116,589
Exploration (1)	40,045	68,640
Development (1)	128,255	40,474
Seismic, capitalized interest, other leasehold costs	16,922	18,313
Acquisitions and investments in oil and gas property/equipment	$ 619,804	$ 244,016

(1) Reported by geography in the subsequent table.

The following table presents our exploration and development capital expenditures by geography:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in thousands)	
Conventional shelf	$ 99,317	$ 93,777
Deepwater	3,072	6,429
Deep shelf	1,816	3,405
Onshore	64,095	5,503
Exploration and development capital expenditures	$ 168,300	$ 109,114

Our 2011 capital expenditures were financed by cash flow from operating activities, cash on hand and additional borrowings. Our 2010 capital expenditures were financed by cash flow from operating activities and cash on hand.

During the nine months ended September 20, 2011, we participated in the drilling of 31 onshore wells and 4 offshore wells, all except one of which were successful. Of the successful onshore wells, nine onshore wells were exploration wells and 21 onshore wells were development wells, with one being in South Texas, one in East Texas and the others in the Permian Basin of West Texas. One onshore well in South Texas was unsuccessful. All of the offshore wells were successful and were drilled on the conventional shelf. One offshore well was an exploration well and the other three were development wells.

During the nine months ended September 30, 2010, we participated in the drilling of five offshore wells, four of which were successful. Of these successful wells, all four were on the conventional shelf with three being exploration wells and one a development well. We also participated in the drilling of two onshore wells, both of which were unsuccessful.

Our onshore acreage has increased during the nine months ended September 30, 2011 from approximately 5,000 net acres to approximately 173,000 net acres with the increases primarily from acreage acquired in East Texas and from the Permian Basin Properties acquisition.

Our total capital expenditure budget for 2011 is $310 million, which excludes acquisitions. Although there has been considerable shuffling of wells and focus areas since the original budget was prepared, we believe that the $310 million continues to be a reasonable estimate of our capital expenditures, excluding acquisitions, for 2011. The budget includes amounts for drilling and evaluation of wells, well completions, facilities capital, recompletions, seismic and leasehold items. Our 2011 capital budget is subject to change as conditions warrant and our budget is sufficiently flexible such that most any change can be made without incurring any contractor breakage or commitment fees.

Capital expenditures associated with development activities for the Permian Basin Properties acquired in May 2011 from the closing date of May 11, 2011 to December 31, 2011 are currently estimated between $70 million and $80 million and are included in the total annual capital expenditure budget described above. For additional information on this acquisition, please see *Financial Statements - Note 2 – Acquisitions* under Part I, Item 1 of this Form 10-Q.

We intend to continue to pursue acquisitions and joint venture opportunities in the future. We are constantly evaluating attractive new opportunities and expect to continue to complement our drilling and exploitation projects with acquisitions providing acceptable rates of return. We anticipate funding our 2011 capital budget and acquisitions with internally generated cash flow, cash on hand, borrowings under our revolving bank credit facility, issuance of our 8.5% Senior Notes, additional long-term debt, or other financings, if and when funds are needed.

Income taxes. During the nine months ended September 30, 2011, we made tax payments of $25.3 million. For the nine months ended September 30, 2010, we received a refund of approximately $99.8 million and made a payment of $4.0 million. For the year 2011 based on current projections, we expect substantially all of our income taxes will be deferred and only minimal payments are expected primarily related to alternative minimum tax. Income tax payments are affected by many factors, with the primary factors being operating results, drilling activity, and plugging and abandonment activity. To the extent that there are variances to our projections, our estimates of income tax payments could increase in the fourth quarter of 2011 or the first quarter of 2012 related to the 2011 tax year.

Dividends. During the nine months ended September 30, 2011, we paid regular cash dividends of $0.04 per common share per quarter. During the nine months ended September 30, 2010, we paid regular cash dividends of $0.04, $0.03 and $0.03 per common share per quarter, respectively. On October 31, 2011, our board of directors declared a cash dividend of $0.04 per common share, payable on December 1, 2011 to shareholders of record on November 16, 2011.

Contractual obligations. Major changes in contractual obligations from those disclosed in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2010 are as follows: 1) asset retirement obligations as disclosed in *Financial Statements - Note 4 – Asset Retirement Obligations* under Part I, Item 1 of this Form 10-Q; 2) additions of principal and interest related to our 8.5% Senior Notes and reductions of principal and interest related to our 8.25% Senior Notes principal as disclosed in *Financial Statements - Note 6 – Long-Term Debt* under Part I, Item 1 of this Form 10-Q; 3) drilling rig contracts with terms of six months or less have commitments of $16.5 million as of September 30, 2011; 4) additional operating lease of $12.3 million for an 11 year office lease; and 5) derivative contracts as disclosed in *Financial Statements - Note 5 – Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

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, 2010. Also refer to the Notes to Condensed Consolidated Financial Statements included in Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

None.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the nine months ended September 30, 2011 did not change materially from the disclosures in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2010. 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, 2010.

Commodity Price Risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil and natural gas, which fluctuate widely. In the past, oil and natural gas price declines and volatility have negatively affected our revenues, net cash provided by operating activities and profitability. We have entered into a limited number of commodity option contracts to help manage a portion of our exposure to commodity price risk from sales of oil during the fiscal years ending December 31, 2011 and 2012. As of September 30, 2011 our derivative instruments outstanding consisted of commodity option contracts relating to approximately 0.4 MMBbls and 1.1 MMBbls of our anticipated production for the balance of 2011 and year 2012, respectively. While these contracts are intended to reduce the effects of volatile oil prices, they may also limit future income if oil prices were to rise substantially over the price established by the hedge. Currently, we do not have any commodity option contracts for natural gas. We do not enter into derivative instruments for speculative trading purposes. For additional details about our commodity derivatives, refer to *Financial Statements – Note 5 – Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

Interest Rate Risk. We currently do not have any derivative instruments related to interest rates. As of September 30, 2011, we had $94 million of floating rate debt outstanding. Borrowings on our revolving bank credit facility are subject to interest rate risk.

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, 2011 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, 2011, 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

Please see the risk factor entitled "*The Company is responding to a federal grand jury investigation that could result in penalties and additional operating restrictions*" under Part II, Item 1A, Risk Factors of this Form 10-Q, for information concerning governmental proceedings.

Item 1A. Risk Factors

Carefully consider the risk factors set forth below, as well as the risk factors included under the caption "Risk Factors" under Part I, Item 1A in the Company's Annual Report on Form 10-K for the year ended December 31, 2010, together with all of the other information included in this document, in the Company's Annual Report on Form 10-K and in the Company's other public filings, press releases and discussions with Company management.

The Company is responding to a federal grand jury investigation that could result in penalties and additional operating restrictions.

The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the Environmental Protection Agency, is conducting a federal grand jury investigation of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico. We are fully cooperating with the investigation. The United States Attorney's Office has recently informed us that they are continuing with their investigation with the intent to seek a criminal disposition. We are not able at this time to estimate our potential exposure, if any, related to this matter.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. We utilize hydraulic fracturing techniques in connection with developing our recently acquired Permian Basin Properties and other properties. The process involves the injection of water, sand and small amounts of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The federal Environmental Protection Agency ("EPA"), however, recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the federal Safe Drinking Water Act's (the "SDWA") Underground Injection Control Program and has begun the process of drafting guidance documents on regulating requirements for companies that plan to conduct hydraulic fracturing using diesel fuel. In addition, a number of federal agencies are analyzing a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with initial results expected to be available by late 2012 and final results by 2014. A committee of the United States House of Representatives also has conducted an investigation of hydraulic fracturing practices. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including states in which we operate. For example, on June 17, 2011, Texas signed into law a bill that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. The disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. In addition, disclosure of proprietary chemical formulas or disclosure of any chemicals used in such formulas to the public could diminish the value of those formulas and could result in competitive harm to us. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recently proposed rules regulating air emissions from oil and gas operations could cause us to incur increased capital expenditures and operating costs.

On July 28, 2011, the Environmental Protection Agency ("EPA") proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development activities may be unsuccessful for many reasons, including adverse weather conditions (such as hurricanes and tropical storms in the Gulf of Mexico), cost overruns, equipment shortages, geological issues and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not assure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells hinder our efforts to replace reserves.

Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, involve a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;

- natural disasters, such as tropical storms, hurricanes and other adverse weather conditions;
- inability to obtain insurance at reasonable rates;
- failure to receive payment on insurance claims in a timely manner, or for the full amount claimed;
- pipe, cement, subsea well or pipeline failures;
- casing collapses or failures;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations or rock compaction; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, encountering naturally occurring radioactive materials, and discharges of brine, well stimulation and completion fluids, toxic gases, or other pollutants into the surface and subsurface environment.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations;
- repairs required to resume operations; and
- loss of reserves.

Offshore operations are also subject to a variety of operating risks related to the marine environment, such as capsizing, collisions and damage or loss from tropical storms, hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate funds available for exploration, exploitation and acquisitions or result in the loss of property and equipment.

Item 5. Other Information

None

Item 6. Exhibits

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

Table of Contents

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on November 3, 2011.

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
2.1	Purchase and Sale Agreement between Opal Resources, LLC and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed May 13, 2011)
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))
4.1	First Supplemental Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 16, 2011)
4.2	Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 16, 2011)
4.3	Form of 8.5% Senior Notes due 2019. (included in Exhibit 4.2)
4.4	Registration Rights Agreement, dated June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 16, 2011)
10.1	Fourth Amended and Restated Credit Agreement, dated May 5, 2011, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 6, 2011)
10.2*	Form of the Executive Annual Incentive Award Agreement for Fiscal Year 2011.
31.1*	Section 302 Certification of Chief Executive Officer.
31.2*	Section 302 Certification of Chief Financial Officer.
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed or furnished herewith.

Exhibit 10.2

W&T OFFSHORE, INC.
AMENDED AND RESTATED INCENTIVE COMPENSATION PLAN

Executive Annual Incentive Award Agreement
For Fiscal Year 2011

This potential Annual Incentive Award (the "***Award***") is granted on August 5, 2011 (the "***Award Date***"), by W&T Offshore, Inc., a Texas corporation (the "***Company***") to you ("***Awardee***" or "***you***").

WHEREAS, the Company in order to induce you to enter into and to continue and dedicate service to the Company and to materially contribute to the success of the Company agrees to grant you this Award;

WHEREAS, this Award is granted to you pursuant to the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, as may be amended from time to time (the "***Plan***"), and the following terms and conditions of this agreement (the "***Agreement***") for the Company's 2011 fiscal year;

WHEREAS, a copy of the Plan has been furnished to you and shall be deemed a part of this Agreement as if fully set forth herein; and

WHEREAS, you desire to accept the Award made pursuant to this Agreement.

NOW, THEREFORE, in consideration of and mutual covenants set forth herein and for other valuable consideration hereinafter set forth, the parties agree as follows:

1. Terms and Conditions. The Award is subject to all the terms and conditions of the Plan. All capitalized terms not defined in this Agreement shall have the meaning stated in the Plan. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the terms of the Plan shall control unless this Agreement expressly states that an exception to the Plan is being made.

2. Definitions. For purposes of this Agreement, the following terms shall have the meanings stated below.

(a) "***Base Salary***" means the base salary you received during the Performance Period, (i) including any amounts deferred pursuant to an election under any 401(k) plan, pre-tax premium plan, deferred compensation plan, or flexible spending account sponsored by the Company or any Subsidiary, and any overtime paid to you as an offshore employee required by your standard work schedule, but (ii) *excluding* any incentive compensation, employee benefit, or other benefit paid or provided under any incentive, bonus or employee benefit plan sponsored by the Company or any Subsidiary, all overtime paid other than as specified in (i) above and/or any excellence award, gains upon stock option exercises, restricted stock grants or vesting, moving or travel expense reimbursement, sign on bonus, imputed income, or tax gross-ups, without regard to whether the payment or gain is taxable income to you.

(b) "***Disability***" means your permanent disability as defined in your Individual Agreement. In the event that there is no existing written Individual Agreement between you and the Company or if any such agreement does not define Disability, the term "***Disability***" shall mean: (i) a physical or mental impairment of sufficient severity that, in the opinion of the Company, (A) you are unable to continue performing the duties assigned to you prior to such impairment or (B) your condition entitles you to disability benefits under any insurance or employee benefit plan of the Company or its Subsidiaries, and (ii) the impairment or condition is cited by the Company as the reason for your termination; *provided, however,* that in all cases, the term Disability shall be applied and interpreted in compliance with section 409A of the Code and the regulations thereunder.

(c) "***Individual Agreement***" means any employment or severance agreement, if any, between you and the Company or any Subsidiary.

(d) "***Performance Goals***" means the performance criteria established by the Committee pursuant to Section 8 of the Plan and set forth in Appendix A attached hereto.

(e) "***Performance Period***" means the Company's complete fiscal year ending December 31, 2011.

(f) "***Total Performance Score***" means the aggregate number of points you are assigned as a result of the Committee's review, analysis and certification of the achievement of the applicable Performance Goals set forth in Appendix A attached hereto for the Performance Period.

3. Effect of Award Agreement. By signing this Agreement, you (a) acknowledge receipt of and represent that you have read and are familiar with this Agreement; (b) accept this Award subject to all of the terms and conditions of the Agreement and the Plan; and (c) agree to accept as binding, conclusive and final all decisions or interpretations of the Committee.

4. Target Award. You are hereby awarded a target Award of % of your Base Salary (referred to herein as your "***Target Award***") subject to the terms and conditions set forth in the Plan and this Agreement. Subject to Sections 5 and 8 below, your Total Performance Score will determine whether you may receive an Award less than, equal to, or greater than your Target Award.

5. Minimum and Maximum Performance Levels. As a condition of payment of the Award, your Total Performance Score must reach 40 or above; Total Performance Scores of 0 through 39.99 (Below Threshold) shall not result in the payment of any portion of your Award. The maximum Total Performance Score you may be assigned shall not exceed 200, nor may the payout of your Award exceed 200% of your Target Award amount.

6. Award Calculation. Your Award will be calculated as follows:

(a) Based on your Total Performance Score, the payout amount of your Award will be determined using the chart below:

Performance Level	Total Performance Score	Percentage of Target Award Paid to You
Maximum	200	200%
Target	100	100%
Threshold	40	40%
Below Threshold	0	0%

(b) *General Terms*.

(i) Payout multiples between the numbers 40 and 200 on the chart in Section 6(a) above will be calculated using straight-line interpolation.

(ii) Any Award that is earned will be paid in cash as soon as practicable after the Committee has certified the applicable Performance Goals were achieved for the Performance Period, but in no event later than the seventy-fifth (75th) day following the date the Performance Period ends.

(iii) You must be employed or newly eligible by September 30 within the Performance Period in order to be eligible to participate in the Plan for the Performance Period.

7. Effect of Termination of Employment. Notwithstanding any provisions to the contrary below in the remainder of this Section 7, in the event of any inconsistency between this Section 7 and any written Individual Agreement you may have, the terms of such an Individual Agreement will control In the event you do not have an Individual Agreement or your Individual Agreement does not address the treatment of Annual Incentive Awards under the Plan, if your employment is terminated at any time on or after the Award Date and before the Award is paid, your Award will be treated as follows:

(a) *Death or Disability*. If your termination of employment is a result of your death or Disability, as determined by the Company in its sole and complete discretion, you will receive a pro-rata Award, if an Award is payable for the Performance Period, calculated based on the number of days during the Performance Period that you were employed with the Company divided by the number of days in the Performance Period (the "***Pro-Rata Award***"). You, your beneficiaries, or your estate, as applicable, will be paid in cash as soon as practicable after the date of your termination of employment following the Committee's review, analysis and certification of all applicable items necessary to calculate your pro-rata Award, but in no event later than the seventy-fifth (75th) day following the date of your termination of employment; *provided*, *however*, that you must have been employed with the Company for a minimum of 90 days during the Performance Period in order to be eligible for a Pro-Rata Award described in this Section 7(a).

(b) *Terminations other than Death or Disability*. Unless your termination of employment is a result of your death or Disability, you must be employed by the Company or a Subsidiary on the date Awards are paid in order to be eligible to receive payment of an Award. You have no vested interest to the Award prior to the Award actually being paid to you by the

Company. If your employment with the Company or a Subsidiary terminates for any reason other than your death or Disability, whether your termination is voluntary or involuntary, with or without cause, you will not be eligible to receive payment of any Award for the Performance Period.

8. Right of the Committee. The Committee has the right to reduce or eliminate your Award for any reason regardless of the amount of your Total Performance Score achieved.

9. Right of the Company and Subsidiaries to Terminate Services. Nothing in this Agreement confers upon you the right to continue in the employ of the Company or any Subsidiary, or interfere in any way with the rights of the Company or any Subsidiary to terminate your employment at any time, with or without cause.

10. Withholding Taxes. The Company may require you to pay to the Company (or the Company's Subsidiary if you are an employee of a Subsidiary of the Company), an amount the Company deems necessary to satisfy its (or its Subsidiary's) current or future obligation to withhold federal, state or local income or other taxes that you incur as a result of the Award. With respect to any such required tax withholding, the Company shall withhold from the payment to be issued to you under this Agreement the amount necessary to satisfy the Company's obligation to withhold taxes.

11. Furnish Information. You agree to furnish to the Company all information requested by the Company to enable it to comply with any reporting or other requirements imposed upon the Company by or under any applicable statute or regulation.

12. No Liability for Good Faith Determinations. The Company, the Committee and the members of the Board shall not be liable for any act, omission or determination taken or made in good faith with respect to this Agreement or the Award granted hereunder.

13. Execution of Receipts and Releases. Any payment of cash to you, or to your legal representative, heir, legatee or distributee, in accordance with the provisions hereof, shall, to the extent thereof, be in full satisfaction of all claims of such Persons hereunder. The Company may require you or your legal representative, heir, legatee or distributee, as a condition precedent to such payment, to execute a release and receipt therefor in such form as the Company shall determine.

14. Notice. All notices required or permitted under this Agreement must be in writing and personally delivered or sent by mail and shall be deemed to be delivered on the date on which it is actually received by the person to whom it is properly addressed or if earlier the date it is sent via certified United States mail.

15. Waiver of Notice. Any person entitled to notice hereunder may waive such notice in writing.

16. Information Confidential. As partial consideration for the granting of the Award hereunder, you hereby agree to keep confidential all information and knowledge, except that which has been disclosed in any public filings required by law, that you have relating to the terms and conditions of this Agreement; *provided*, *however*, that such information may be disclosed as required by law and may be given in confidence to your spouse and tax and financial advisors. In the event any breach of this promise comes to the attention of the Company, it shall take into consideration that breach in determining whether to recommend the grant of any future similar award to you, as a factor weighing against the advisability of granting any such future award to you.

17. Nontransferability. Neither this Agreement nor this Award subject to this Agreement shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance or garnishment by your creditors or your beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to the Agreement shall be exercisable during your lifetime only by yourself or, if necessary, your guardian or legal representative.

18. Successors. This Agreement shall be binding upon you, your legal representatives, heirs, legatees and distributees, and upon the Company, its successors and assigns.

19. Severability. If any provision of this Agreement is held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining provisions hereof, but such provision shall be fully severable and this Agreement shall be construed and enforced as if the illegal or invalid provision had never been included herein.

20. Amendment. The Committee may amend this Agreement at any time; *provided*, *however*, that no such amendment may adversely affect your rights under this Agreement without your consent, except to the extent such amendment is reasonably determined by the Committee, in its sole discretion, to be necessary to comply with applicable law or to prevent a detrimental accounting impact. No amendment or addition to this Agreement shall be effective unless in writing.

21. Headings. The titles and headings of Sections are included for convenience of reference only and are not to be considered in construction of the provisions hereof.

22. Governing Law. All questions arising with respect to the provisions of this Agreement shall be determined by application of the laws of Texas, without giving any effect to any conflict of law provisions thereof, except to the extent Texas state law is preempted by federal law.

23. Consent to Texas Jurisdiction and Venue. You hereby consent and agree that state courts located in Harris County, Texas and the United States District Court for the Southern District of Texas each shall have personal jurisdiction and proper venue with respect to any dispute between you and the Company arising in connection with the Award or this Agreement. In any dispute with the Company, you will not raise, and you hereby expressly waive, any objection or defense to any such jurisdiction as an inconvenient forum.

24. The Plan. This Agreement is subject to all the terms, conditions, limitations and restrictions contained in the Plan.

[Signature Page to Follow]

You must sign this Agreement and return it to W&T Offshore, Inc.'s Manager of Human Resources on or before August 15, 2011, or the potential Award will be forfeited.

Awardee's Social Security Number

Awardee Signature

Date

President

Date: August 5, 2011

Appendix A

Performance Goals

The Performance Goals for your 2011 Annual Incentive Award shall be comprised of two equal portions: the "Business Criteria" and the "Company and Individual Performance Criteria." The Business Criteria will comprise 50% of your potential Award, and the Company and Individual Performance Criteria will comprise the remaining 50% of your potential Award.

Your Total Performance Score will be calculated using the criteria and the scales below. The Committee shall review, analyze and certify the achievement of each of the criterion below, either for the Company or yourself, as applicable, and shall determine your Total Performance Score according to the aggregate number of points you receive from each of the scales below.

Part 1. Business Criteria

Target Criteria	Percentage of Weight Relative to your Total Potential Award	Points
Production Growth: equivalent production at least 105 Bcfe for YE 2011	20%	0-40
Reserve Growth: Increase in reserves of 133 Bcfe over 2010 YE reserves (485.4 Bcfe), excluding 2011 YE production.	20%	0-40
F&D Costs: not to exceed $3.50 per Mcfe at year end 2011	5%	0-10
LOE & G&A: 2011 LOE and G&A per Mcfe of production no more than a 7% increase in LOE and G&A per Mcfe of production, measured against 2010 LOE and G&A per Mcfe of production (excluding hurricane expenses and insurance credits for such expenses)	5%	0-10
Total	50%	100

The number of points you receive on each individual scale shall be determined as follows, using a straight-line interpolation:

(a) Production Growth – Year end Production for 2011

Performance Level	Points
Maximum: greater than 125 Bcfe	40
Target: 105 Bcfe in 2011	20
Threshold: 96 Bcfe in 2011	10
Below Threshold	0

(b) Reserve Growth – In 2011 increase in reserves over 2010 YE reserves (485.4 Bcfe), excluding reductions from 2011 YE production.

Performance Level	Points
Maximum: increase in reserves greater than 150 Bcfe over 2010 YE reserves	40
Target: increase in reserves of 133 Bcfe over 2010 YE reserves	20
Threshold: increase in reserves of 116 Bcfe over 2010 YE reserves	10
Below Threshold	0

(c) F&D Costs: not to exceed a specified dollar amount per Mcfe at year end 2011. "F&D" is defined as the total capital dollars spent in 2011 plus changes in ARO; divided by proved reserves added for the year 2011.

Performance Level	Points
Maximum: F&D costs not to exceed $3.00 per Mcfe at year end 2011	10
Target: F&D costs not to exceed $3.50 per Mcfe at year end 2011	5
Threshold: not to exceed $3.61 per Mcfe at year end 2011	2.5
Below Threshold	0

(d) Combined LOE & G&A: 2011 LOE and G&A per Mcfe of production no more than a percentage increase in LOE and G&A per Mcfe of production, measured against 2010 LOE and G&A per Mcfe of production (both measurements excluding hurricane expenses and insurance credits for such expenses).

Performance Level	Points
Maximum: less than a 3% increase in LOE and G&A per Mcfe of production, measured against 2010 LOE and G&A per Mcfe of production	10
Target: no more than a 7% increase in LOE and G&A per Mcfe of production, measured against 2010 LOE and G&A per Mcfe of production	5
Threshold: no more than a 9% increase in LOE and G&A per Mcfe of production, measured against 2010 LOE and G&A per Mcfe of production	2.5
Below Threshold	0

Part 2. Company and Individual Performance Criteria

Criteria	Percentage of Weight Relative to your Total Potential Award	Points
Overall Company Performance Conditions		
2011 Net Earnings Per share (diluted)	20%	0-40
2011 Adjusted EBITDA Margin Percentage	20%	0-40
Individual Performance Conditions		
Individual Performance as assessed by management for year 2011	10%	0-20
Total for Overall Company Performance Conditions and Individual Performance Conditions Combined	50%	100

The number of points you receive on each individual scale shall be determined as follows, on straight-line interpolation:

(a) Net Earnings Per Share (diluted), being "EPS" for YE2011 (excluding dividends paid in 2011)

Performance Level	Points
Maximum: EPS greater than $1.30/share	40
Target: EPS greater than $1.00/share	20
Threshold: EPS greater than $.85/share	10
Below Threshold	0

(b) Adjusted EBITDA Margin Percentage YE 2011

Performance Level	Points
Maximum: Adjusted EBITDA Margin percentage greater than 70% YE 2011	40
Target: Adjusted EBITDA Margin percentage greater than 60% YE 2011	20
Threshold: Adjusted EBITDA Margin greater than 55% YE 2011	10
Below Threshold	0

(c) Individual Performance in 2011, assessed by management

Performance Level	Points
Maximum – Far Exceeded Expectations	20
Target – Exceeded Expectations	10
Threshold – Met expectations	5
Below Threshold	0

Exhibit 31.1

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

I, Tracy W. Krohn, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2011

/s/ TRACY W. KROHN
Tracy W. Krohn
Chief Executive Officer

Exhibit 31.2

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

I, John D. Gibbons, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2011

/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, 2011 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 3, 2011	/s/ TRACY W. KROHN
	Tracy W. Krohn Chief Executive Officer
Date: November 3, 2011	/s/ JOHN D. GIBBONS
	John D. Gibbons Senior Vice President, Chief Financial Officer and Chief Accounting Officer