W&T OFFSHORE INC
Form 10-Q
August 07, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2014

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to ________________

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas (State of incorporation)	72-1121985 (IRS Employer Identification Number)
Nine Greenway Plaza, Suite 300	
Houston, Texas (Address of principal executive offices)	77046-0908 (Zip Code)

(713) 626-8525

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.   Yes þ   No ¨

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

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

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

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

As of August 5, 2014, there were 75,656,558 shares outstanding of the registrant's common stock, par value $0.00001.

W&T OFFSHORE, INC. AND SUBSIDIARIES

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2014	December 31, 2013
	(In thousands, except per share data)	
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$23,847	$15,800
Receivables:		
Oil and natural gas sales	94,417	96,752
Joint interest and other	26,584	27,984
Income tax	120	3,120
Total receivables	121,121	127,856
Prepaid expenses and other assets	38,644	29,946
Total current assets	183,612	173,602
Property and equipment - at cost:		
Oil and natural gas properties and equipment (full cost method, of which $122,713 at June 30, 2014 and $116,612 at December 31, 2013 were excluded from amortization)	7,628,208	7,339,097
Furniture, fixtures and other	21,660	21,431
Total property and equipment	7,649,868	7,360,528
Less accumulated depreciation, depletion and amortization	5,326,074	5,084,704
Net property and equipment	2,323,794	2,275,824
Restricted deposits for asset retirement obligations	23,723	37,421
Other assets	18,643	20,455
Total assets	$2,549,772	$2,507,302
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$140,495	$145,212
Undistributed oil and natural gas proceeds	39,202	42,107
Asset retirement obligations	69,923	77,785
Accrued liabilities	31,299	28,000
Total current liabilities	280,919	293,104
Long-term debt, less current maturities	1,224,262	1,205,421
Asset retirement obligations, less current portion	287,680	276,637
Deferred income taxes	189,902	178,142

Other liabilities	13,622	13,388
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value; 20,000,000 shares authorized; 0 issued at June 30, 2014 and December 31, 2013	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 78,525,731 issued and 75,656,558 outstanding at June 30, 2014; 78,460,872 issued and 75,591,699 outstanding at December 31, 2013	1	1
Additional paid-in capital	410,642	403,564
Retained earnings	166,911	161,212
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	553,387	540,610
Total liabilities and shareholders' equity	$2,549,772	$2,507,302

See Notes to Condensed Consolidated Financial Statements.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands except per share data) (Unaudited)			
Revenues	$262,994	$235,383	$517,510	$494,605
Operating costs and expenses:				
Lease operating expenses	61,765	68,248	117,384	127,590
Production taxes	1,842	1,780	3,834	3,569
Gathering and transportation	3,985	4,608	9,281	9,052
Depreciation, depletion, amortization and accretion	128,236	99,896	251,542	208,767
General and administrative expenses	19,682	19,868	43,270	40,955
Derivative (gain) loss	13,079	(12,840)	20,571	(9,473)
Total costs and expenses	228,589	181,560	445,882	380,460
Operating income	34,405	53,823	71,628	114,145
Interest expense:				
Incurred	21,454	21,536	42,912	42,770
Capitalized	(2,159)	(2,532)	(4,231)	(4,964)
Income before income tax expense	15,110	34,819	32,947	76,339
Income tax expense	5,273	12,423	11,921	27,325
Net income	$9,837	$22,396	$21,026	$49,014
Basic and diluted earnings per common share	$0.13	$0.29	$0.28	$0.64
Dividends declared per common share	$0.10	$0.09	$0.20	$0.17

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock Outstanding		Additional Paid-In	Retained	Treasury Stock		Total Shareholders'
	Shares	Value	Capital	Earnings	Shares	Value	Equity
	(In thousands) (Unaudited)						
Balances at December 31, 2013	75,592	$ 1	$ 403,564	$ 161,212	2,869	$ (24,167)	$ 540,610
Cash dividends	—	—	—	(15,129)	—	—	(15,129)
Share-based compensation	65	—	7,644	—	—	—	7,644
Other	—	—	(566)	(198)	—	—	(764)
Net income	—	—	—	21,026	—	—	21,026
Balances at June 30, 2014	75,657	$ 1	$ 410,642	$ 166,911	2,869	$ (24,167)	$ 553,387

See Notes to Condensed Consolidated Financial Statements.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2014 (In thousands) (Unaudited)			2013		
Operating activities:						
Net income	$	21,026		$	49,014	
Adjustments to reconcile net income to net cash provided by operating activities:						
Depreciation, depletion, amortization and accretion		251,542			208,767	
Amortization of debt issuance costs and premium		366			910	
Share-based compensation		7,644			4,950	
Derivative (gain) loss		20,571			(9,473	)
Cash payments on derivative settlements (realized)		(14,310	)		(2,310	)
Deferred income taxes		11,921			23,726	
Changes in operating assets and liabilities:						
Oil and natural gas receivables		2,335			17,063	
Joint interest and other receivables		3,550			38,635	
Income taxes		2,918			8,579	
Prepaid expenses and other assets		4,439			(12,381	)
Asset retirement obligation settlements		(30,338	)		(32,886	)
Accounts payable, accrued liabilities and other		(10,614	)		2,768	
Net cash provided by operating activities		271,050			297,362	
Investing activities:						
Acquisition of property interest in oil		(53,363	)		—	

and natural gas properties						
Investment in oil and natural gas properties and equipment		(212,680	)		(299,213	)
Purchases of furniture, fixtures and other		(1,715	)		(981	)
Net cash used in investing activities		(267,758	)		(300,194	)
Financing activities:						
Borrowings of long-term debt - revolving bank credit facility		220,000			252,000	
Repayments of long-term debt - revolving bank credit facility		(200,000	)		(239,000	)
Dividends to shareholders		(15,129	)		(12,795	)
Other		(116	)		(342	)
Net cash provided by (used in) financing activities		4,755			(137	)
Increase (decrease) in cash and cash equivalents		8,047			(2,969	)
Cash and cash equivalents, beginning of period		15,800			12,245	
Cash and cash equivalents, end of period	$	23,847		$	9,276	

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 exploration, development and acquisition of oil and natural gas properties. Our interest in fields, leases, structures and equipment are primarily owned by W&T Offshore, Inc. (the “Parent Company”) and our wholly-owned subsidiary, W&T Energy VI, LLC (“Energy VI”).

Interim Financial Statements. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) for interim periods and the appropriate rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, the condensed consolidated financial statements do not include all of the information and footnote disclosures required by GAAP for complete financial statements for annual periods. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included.

Operating results for interim periods are not necessarily indicative of the results that may be expected for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2013.

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

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

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

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

Adjustment related to additional volumes. In January 2014, we identified that we had been receiving an erroneous conversion factor from a third party that had the effect of understating natural gas production at our Viosca Knoll 783 field (Tahoe). The incorrect conversion factor had been used on all natural gas production from the field since we acquired it in 2011. The effect of using this incorrect conversion factor did not affect revenues, operating cash flows or royalty payments to the federal government but did impact reported natural gas production and the calculation of depletion expense. We performed an analysis of the information, assessing both quantitative and qualitative factors, and determined that the impact on our net income reported for quarters in 2013, as well as the impact to our earnings trend, was not material to the previously reported results, thus the adjustment was recognized in the fourth quarter of 2013. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the second quarter of 2013 were: an increase in natural gas production volumes of 254 million cubic feet (“MMcf”) (with no corresponding increase in revenue); an increase to depreciation, depletion, amortization and accretion expense (“DD&A”) of $0.7 million; and a decrease to net income of $0.5 million. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the first half of 2013 were: an increase in natural gas production volumes of 518 MMcf (with no corresponding increase in revenue); an increase to DD&A of $1.5 million; and a decrease to net income of $1.0 million.

Recent Accounting Developments. In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09 (“ASU 2014-09”), Summary and Amendments That Create Revenue from Contracts and Customers (Topic 606). ASU 2014-09 amends and replaces current revenue recognition requirements, including most industry-specific guidance. The revised guidance establishes a five step approach to be utilized in determining when, and if, revenue should be recognized. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2016. Upon application, an entity may elect one of two methods, either restatement of prior periods presented or recording a cumulative adjustment in the initial period of application. We have not determined the effect ASU 2014-09 will have on the recognition of our revenue, if any, nor have we determined the method we will utilize upon adoption, which would be in the first quarter of 2017.

2. Acquisitions and Divestitures

2014 Acquisition

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

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

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

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

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

The Woodside Properties were not included in our consolidated results until the property transfer date, which occurred in May 2014. For the three and six months ended June 30, 2014, the Woodside Properties accounted for $6.9 million of revenues, $0.7 million of direct operating expenses, $2.2 million of DD&A and $1.4 million of income taxes, resulting in $2.6 million of net income. Also, we incurred $0.1 million of expenses associated with acquisition and transition activities related to the acquisition of the Woodside Properties for the three and six months ended June 30, 2014. The net income attributable to the Woodside Properties does not reflect certain expenses, such as general and administrative expenses ("G&A") and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Woodside Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenue	$272,022	$251,361	$540,397	$528,291
Net income	12,206	27,602	27,236	60,470
Basic and diluted earnings per common share	0.16	0.36	0.36	0.79

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues (a)	$9,028	$15,978	$22,887	$33,686
Direct operating expenses (a)	1,805	2,591	4,417	4,990
DD&A (b)	3,305	4,917	8,218	10,204
G&A (c)	200	200	400	400
Interest expense (d)	80	240	320	480
Capitalized interest (e)	(6)	20	(22)	(13)
Income taxes expense (f)	1,275	2,804	3,344	6,169

The sources of information and significant assumptions are described below:

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

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

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

(d) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $53.4 million, which equates to the cash component of the acquisition purchase price, and an interest rate of 1.8%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.

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

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

The pro forma adjustments do not include adjustments related to any other acquisitions or divestitures.

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

2013 Acquisition

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

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

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

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

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

The Callon Properties were not included in our consolidated results until the respective property transfer dates, which occurred during the fourth quarter of 2013. For the three months ended June 30, 2014, the Callon Properties accounted for $8.7 million of revenues, $1.0 million of direct operating expenses, $1.6 million of DD&A and $2.1

million of income taxes, resulting in $4.0 million of net income. For the six months ended June 30, 2014, the Callon Properties accounted for $17.4 million of revenues, $2.0 million of direct operating expenses, $7.0 million of DD&A and $2.9 million of income taxes, resulting in $5.5 million of net income. The net income attributable to the Callon Properties does not reflect certain expenses, such as G&A and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Callon Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate. There were no expenses associated with acquisition activities and transition activities related to the acquisition of the Callon Properties for the three or six months ended June 30, 2013.

Consistent with the computation of pro forma financial information presented in Item 8, Financial Statements and Supplementary Data, in the Annual Report on Form 10-K for the year end December 31, 2013, the unaudited pro forma financial information was computed as if the acquisition of the Callon Properties had been completed on January 1, 2012. The financial information was derived from W&T's audited historical consolidated financial statements for annual periods, W&T's unaudited historical condensed consolidated financial statements for interim periods, the Callon Properties' audited historical financial statement for 2012 and the Callon Properties' unaudited historical financial statements for interim periods.

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

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

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

	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Revenue	$243,840	$514,415
Net income	24,020	53,722
Basic and diluted earnings per common share	0.32	0.71

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

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

	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Revenues (a)	$ 8,457	$ 19,810
Direct operating expenses (a)	1,886	3,930
DD&A (b)	3,714	7,945
Interest expense (c)	415	830
Capitalized interest (d)	(56)	(138)
Income taxes expense (e)	874	2,535

The sources of information and significant assumptions are described below:

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

(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Callon Properties' costs, reserves and production into our full cost pool in order to compute such amounts. The purchase price allocated to unevaluated properties for oil and natural gas interests was excluded from the DD&A expense estimation. ARO was estimated by W&T management.
(c) The acquisition was assumed to be funded entirely with borrowed funds. Interest expense was computed using assumed borrowings of $83.0 million, which equates to the cash component of the acquisition purchase price, and an interest rate of 2.0%, which equates to the rates applied to incremental borrowings on the revolving bank credit facility.
(d) The change to capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings. The negative amount represents a decrease to net expenses.
(e) Income tax expense was computed using the 35% federal statutory rate.

The pro forma adjustments do not include adjustments related to any other acquisitions or divestitures.

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

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

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

3. Asset Retirement Obligations

Our ARO primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws.

A summary of the changes to our ARO is as follows (in thousands):

Balance, December 31, 2013	$	354,422	
Liabilities settled		(30,338	)
Accretion of discount		10,112	
Liabilities assumed through acquisition (1)		15,086	
Liabilities incurred		755	
Revisions of estimated liabilities (2)		7,566	
Balance, June 30, 2014		357,603	
Less current portion		69,923	
Long-term	$	287,680	

(1) Includes the Woodside Properties acquisition and another immaterial acquisition.

(2) Revisions were primarily due to increased estimates related to work requiring coiled tubing at two locations and removal of a platform at one location.

4. Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of our oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. All of the derivative counterparties are also lenders or affiliates of lenders participating in our revolving bank credit facility. We are exposed to credit loss in the event of nonperformance by the derivative counterparties; however, we currently anticipate that each of our derivative counterparties will be able to fulfill their contractual obligations. Additional collateral is not required by us due to the derivative counterparties' collateral rights as lenders and we do not require collateral from our derivative counterparties.

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

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

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

		Swaps – Oil					
		Priced off Brent (ICE)		Priced off WTI (NYMEX)		Priced off LLS (ARGUS)	
Termination Period		Notional Quantity (Bbls)	Weighted Average Contract Price	Notional Quantity (Bbls)	Weighted Average Contract Price	Notional Quantity (Bbls)	Weighted Average Contract Price
2014:	3rd Quarter	165,600	$ 97.38	62,000	$ 97.01	828,000	$ 97.69
	4th Quarter	156,400	97.37	—	—	460,000	98.12
		322,000	$ 97.37	62,000	$ 97.01	1,288,000	$ 97.84

Bbls = barrels

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

	June 30, 2014	December 31, 2013
Prepaid and other assets	$—	$ 141
Accrued liabilities	15,543	9,423

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Derivative (gain) loss:				
Realized	$9,640	$(1,961)	$14,310	$2,310
Unrealized	3,439	(10,879)	6,261	(11,783)
Total	$13,079	$(12,840)	$20,571	$(9,473)

Offsetting Commodity Derivatives. As of June 30, 2014 and December 31, 2013, all of our derivative agreements allowed for netting of derivative gains and losses upon settlement. In general, the terms of the agreements provide for offsetting of amounts payable or receivable between us and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency. If an event of default were to occur causing an acceleration of payment under our revolving bank credit facility, that event may also trigger an acceleration of settlement of our derivative instruments. If we were required to settle all of our open derivative instruments, we would be able to net payments and receipts per counterparty pursuant to the derivative agreements. Although our derivative agreements allow for netting, which would allow for recording assets and liabilities per counterparty on a net basis, we account for our derivative contracts on a gross basis per contract as either an asset or liability.

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

	June 30, 2014		December 31, 2013	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amounts presented in the balance sheet	$—	$ 15,543	$ 141	$ 9,423
Amounts not offset in the balance sheet	—	—	(141)	(141)
Net Amounts	$—	$ 15,543	$—	$ 9,282

5. Long-Term Debt

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

	June 30, 2014	December 31, 2013
8.50% Senior Notes	$900,000	$900,000
Debt premium, net of amortization	14,262	15,421
Revolving bank credit facility	310,000	290,000
Total long-term debt	1,224,262	1,205,421
Current maturities of long-term debt	—	—
Long term debt, less current maturities	$1,224,262	$1,205,421

At June 30, 2014 and December 31, 2013, the balance outstanding of our senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the "8.50% Senior Notes"), was classified as long-term at their carrying value. Interest on the 8.50% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the 8.50% Senior Notes is 8.4%, which includes amortization of debt issuance costs and premiums. We are subject to various financial and other covenants under the indenture governing the 8.50% Senior Notes and we were in compliance with those covenants as of June 30, 2014.

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

At June 30, 2014 and December 31, 2013, we had $0.6 million and $0.4 million, respectively, of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 2.9% for the six months ended June 30, 2014 for borrowings under the revolving bank credit facility. The estimated annual effective interest rate includes amortization of debt issuance costs and excludes commitment fees and other costs. As of June 30, 2014, our borrowing base was $750.0 million and our borrowing availability was $439.4 million.

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

For information about fair value measurements for our 8.50% Senior Notes and revolving bank credit facility, refer to Note 6.

6. Fair Value Measurements

We measure the fair value of our derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for the fair value measurement of our derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads and published commodity futures prices. The fair value of our 8.50% Senior Notes is based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates.

The following table presents the fair value of our derivative financial instruments, 8.50% Senior Notes and revolving bank credit facility (in thousands):

		June 30, 2014		December 31, 2013	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ —	$ 15,543	$ 141	$ 9,423
8.50% Senior Notes	Level 2	—	974,250	—	962,460
Revolving bank credit facility	Level 2	—	310,000	—	290,000

As described in Note 4, our derivative financial instruments are reported in the balance sheet at fair value and changes in fair value are recognized currently in earnings. The 8.50% Senior Notes and revolving bank credit facility are reported in the balance sheet at their carrying value as described in Note 5.

7. Share-Based Compensation and Cash-Based Incentive Compensation

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our shareholders, and amendments to the Plan were approved by our shareholders in May 2013. As allowed by the Plan, during the six months ended June 30, 2014, and in 2013 and 2012, the Company granted restricted stock units ("RSUs") to certain of its employees. RSUs are a long-term compensation component of the Plan, which are granted to only certain employees, and are subject to adjustments at the end of the applicable performance period based on the achievement of certain predetermined criteria. In addition to share-based compensation, the Company may grant to its employees cash-based incentive awards, which are a short-term component of the Plan and are based on the Company and the employee achieving certain pre-defined performance criteria.

During the six months ended June 30, 2014, RSUs granted were subject to a combination of performance criteria, which was comprised of: (i) net income before income tax expense, net interest expense, depreciation, depletion, amortization, accretion and certain other items ("Adjusted EBITDA") for 2014 and (ii) Adjusted EBITDA as a percent of total revenue ("Adjusted EBITDA Margin") for 2014. Adjustments range from 0% to 100% dependent upon actual results compared against pre-defined performance levels.

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

During 2012, RSUs granted were subject to a combination of performance criteria, which was comprised of: (i) earnings per share for 2012; and (ii) the Company's TSR ranking against peer companies' TSR for 2012, 2013 and

January 1, 2014 to October 31, 2014. Pursuant to the Plan, discretionary authority was exercised for certain non-executive employees, which reduced the forfeitures that would have occurred through application of the pre-defined performance measurement.

All RSUs granted to date are subject to employment-based criteria and vesting occurs in December of the second year after the grant. For example, the RSUs granted during 2012 will vest in December 2014 to eligible employees.

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

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

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

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

Awards Based on Restricted Stock to Non-Employee Directors. As of June 30, 2014, all of the unvested shares of Restricted Shares outstanding were issued to the non-employee directors. Restricted Shares are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period. The holders of Restricted Shares generally have the same rights as a shareholder of the Company with respect to such Restricted Shares, including the right to vote and receive dividends or other distributions paid with respect to the Restricted Shares. The fair value of Restricted Shares was estimated by using the Company's closing price on the grant date.

A summary of activity in 2014 related to Restricted Shares awarded to non-employee directors is as follows:

	Restricted Shares	
	Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested, December 31, 2013	43,840	$ 15.96
Granted	18,815	18.60
Vested	(19,445)	18.00
Nonvested, June 30, 2014	43,210	$ 16.20

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

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

Total	43,210

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

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

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

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

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

A summary of activity in 2014 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2013	1,331,753	$ 14.96
Granted	1,178,326	16.86
Vested	(4,662)	16.26
Forfeited	(36,099)	15.54
Nonvested, June 30, 2014	2,469,318	$ 15.85

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

	RSUs
2014 - subject to service requirements	350,319
2014 - subject to service and other requirements (1)	66,723
2015 - subject to service requirements	705,176
2015 - subject to service and other requirements (2)	180,211
2016 - subject to service requirements	3,400
2016 - subject to service and other requirements (3)	1,163,489
Total	2,469,318

(1) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 150% of amounts granted.
(2) In addition to service requirements, these RSUs are also subject to TSR performance requirements not yet measureable, with awards ranging from 0% to 200% of amounts granted.
(3) In addition to service requirements, these RSUs are also subject to Company specific performance requirements not yet measureable, with awards ranging from 0% to 100% of amounts granted.

The grant date fair value of RSUs granted during the six months ended June 30, 2014 and 2013 was $19.9 million and $12.8 million, respectively. The fair value of RSUs that vested during the six months ended June 30, 2014 was $0.1 million. During the six months ended June 30, 2013, there was no vesting of RSUs.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Share-based compensation expense from:				
Restricted stock	$84	$99	$183	$198
Restricted stock units	3,625	2,596	6,161	4,752
Common shares	178	—	1,300	—
Total	$3,887	$2,695	$7,644	$4,950
Share-based compensation tax benefit:				
Tax benefit computed at the statutory rate	$1,360	$943	$2,675	$1,733

Unrecognized Share-Based Compensation. As of June 30, 2014, unrecognized share-based compensation expense related to our awards of Restricted Shares, RSUs and common stock was $0.7 million, $23.8 million and $0.6 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2017 for Restricted Shares, November 2016 for RSUs and February 2015 for awards based on common shares.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees and payable in cash. (In the case of the award to the CEO, the awards for 2014 and 2013 are paid in shares of common stock as described above.) These awards are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

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

	Three Months Ended June 30,	Six Months Ended June 30,

	2014	2013	2014	2013
Share-based compensation included in:				
General and administrative (1)	$3,887	$2,695	$7,644	$4,950
Cash-based incentive compensation included in:				
Lease operating expense	475	747	1,777	2,140
General and administrative (1)	1,532	2,024	3,313	5,554
Total charged to operating income	$5,894	$5,466	$12,734	$12,644

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

8. Income Taxes

Income tax expense of $5.3 million and $11.9 million was recorded during the three and six months ended June 30, 2014, respectively. Our effective tax rate for the three and six months ended June 30, 2014 was 34.9% and 36.2%, respectively. The rate for the three months ended June 30, 2014 differed from the federal statutory rate of 35.0% primarily as a result of adjustments to a revised full-year forecasted rate. The rate for the six months ended June 30, 2014 differed from the federal statutory rate primarily as a result of state income taxes and other permanent items. Income tax expense of $12.4 million and $27.3 million was recorded during the three and six months ended June 30, 2013, respectively. The effective tax rate for the three and six months ended June 30, 2013 was 35.7% and 35.8%, respectively, and differed from the federal statutory rate primarily as a result of state income taxes.

During the six months ended June 30, 2014, we received $3.0 million of refunds. During 2013, we received refunds of $59.1 million, of which $9.5 million of these refunds have been accounted for as unrecognized tax benefits. We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the three and six months ended June 30, 2014 and 2013, we had less than $0.1 million of accrued interest expense related to our unrecognized tax benefit. As of June 30, 2014 and December 31, 2013, we had a valuation allowance related to state net operating losses. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. The tax years from 2010 through 2013 remain open to examination by the tax jurisdictions to which we are subject.

9. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income	$9,837	$22,396	$21,026	$49,014
Less portion allocated to nonvested shares	100	275	219	556
Net income allocated to common shares	$9,737	$22,121	$20,807	$48,458
Weighted average common shares outstanding	75,605	75,223	75,581	75,215
Basic and diluted earnings per common share	$0.13	$0.29	$0.28	$0.64
Shares excluded due to being anti-dilutive (weighted-average)	—	859	—	864

10. Dividends

During the six months ended June 30, 2014 and 2013, we paid regular cash dividends per common share of $0.20 and $0.17, respectively. On August 6, 2014, our board of directors declared a cash dividend of $0.10 per common share, payable on September 12, 2014 to shareholders of record on August 22, 2014.

11. Contingencies

Notice of Suspension and Debarment. In November 2013, W&T Offshore, Inc., the Parent Company, received a Notice of Suspension and Proposed Debarment and a Notice of Clean Water Act Listing from the U.S. Environmental Protection Agency (the "EPA"). The Notices were directed to only the Parent Company and do not name or apply to our wholly-owned subsidiaries. The first Notice suspended the Parent Company and proposed a three year debarment from participation in future federal contracts, including future federal oil and gas leases, and assistance activities and renders the Parent Company ineligible to receive any federal contracts or approved subcontracts or to act as an agent or representative on behalf of another in such transaction, or receive certain federal benefits. The second Notice provided a narrower prohibition on federal contracts or benefits for the Parent Company. The Notices stemmed from the Parent Company's previously disclosed plea agreement and corporate conviction on two criminal counts as described in Item 8, Financial Statements and Supplementary Data, in our Annual Report on Form 10-K for the year end December 31, 2013.

The Notices prevented the Parent Company from obtaining federal oil and gas leases, whether at a future lease sale or an existing lease by assignment. The Notices did not affect current or future drilling or production operations of the existing lease ownership of the Parent Company.

During the third quarter of 2014, the EPA Suspension and Debarment Official removed the suspension and proposed debarment and reinstated the Parent Company from the prohibition in the second Notice after the Parent Company filed submissions to contest the limitations in both Notices and to demonstrate that it corrected the violations and is a responsible operator. See Note 12, Subsequent Events, regarding the lifting the suspension and proposed debarment received from the EPA on August 5, 2014.

Waiver concerning certain supplement bonding requirements from the Bureau of Ocean Energy Management (“BOEM”). In November and December 2013, W&T Offshore, Inc. received letters from the BOEM claiming that it no longer qualified for a waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging, and abandonment liabilities. These letters pertain to the Parent Company’s prior supplemental bonding waiver. Our wholly-owned subsidiary, Energy VI, is not exempt from supplemental bonding under BOEM’s procedures and therefore such wholly-owned subsidiary provides supplemental bonding for its plugging and abandonment liabilities. The supplemental bonding requirements are separate and distinct from the suspension and debarment issue described above. The letters notified the Parent Company that it must provide supplemental bonding on certain of its offshore leases, rights of way and rights of use and easement in the Gulf of Mexico.

In response, in January 2014, the Company filed a Petition for Stay Pending Appeal and Request for Interim Relief with the U.S. Department of Interior's Board of Land Appeals ("IBLA"). In addition, we provided additional information to the BOEM and had numerous discussions with the BOEM staff. On May 8, 2014, an order was issued by the IBLA in which it set aside the November 2013 BOEM order and remanded the case to the BOEM for its consideration. On May 16, 2014, the Parent Company was informed by the BOEM that under applicable federal regulations it now qualifies for a waiver of certain supplemental bonding requirements for potential offshore decommissioning liabilities (including plugging and abandonment).

Notification by ONRR of fine for non-compliance. In December 2013 and January 2014, we were notified by the Office of Natural Resources Revenue (“ONRR”) of an underpayment of royalties on certain Federal offshore oil and gas leases that cumulatively approximated $30,000 over several years, which represents 0.0045% of royalty payments paid by us during the same period of the underpayment. In March 2014, we received notice from the ONRR of a statutory fine of $2.3 million relative to such underpayment. We believe the fine is excessive and extreme considering the circumstances and in relation to the amount of underpayment. On April 23, 2014, we filed a request for a hearing on the record and a general denial of ONRR’s allegations contained in the notice. We intend to contest the fine to the fullest extent possible. The ultimate resolution may result in a waiver of the fine, a reduction of the fine, or payment of the full amount plus interest covering several years. As no amount has been determined as more likely than any other within the range of possible resolutions, no amount has been accrued as of June 30, 2014 per authoritative guidance. However, we cannot state with certainty that our estimate of the exposure is accurate concerning this matter.

Insurance Claims. During the fourth quarter of 2012, underwriters of W&T’s excess liability policies (“Excess Policies”) (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company, XL Specialty Insurance Company and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas seeking a determination that our Excess

Policies do not cover removal-of-wreck and debris claims arising from Hurricane Ike to the extent we have first exhausted the limits of our Energy Package (defined as certain insurance policies relating to our oil and gas properties which includes named windstorm coverage) with only removal-of-wreck and debris claims. The court consolidated the various suits filed by the underwriters. In January 2013, we filed a motion for summary judgment seeking the court's determination that such Excess Policies do not require us to exhaust the limits of our Energy Package policies with only removal-of-wreck and debris claims. In July 2013, the District Court ruled in favor of the underwriters, adopting their position that the Excess Policies cover removal-of-wreck and debris claims only to the extent the limits of our Energy Package policies have been exhausted with removal-of-wreck and debris claims. We appealed the decision in the United States Court of Appeals for the Fifth Circuit and, in June 2014, the Court reversed the District Court's ruling and ruled in our favor. The underwriters filed three separate briefs requesting a rehearing or a certification to the Texas Supreme Court, all of which the Court denied. As the limits of the Energy Package have been exhausted, we have filed and anticipate filing claims of up to approximately $46.3 million under the Excess Policies and ultimately expect to receive recovery of claims. Removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Condensed Consolidated Balance Sheets and recoveries from claims made on these Excess Policies will be recorded as reductions in this line item, which will reduce our future DD&A rate.

Royalties. In 2009, the Company recognized $5.3 million in allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited the calculations and support related to this usage fee, and in the third quarter of 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue of $4.7 million in the third quarter of 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR and we are pursuing our claim to resolve the matter.

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

Contingent Liability Recorded. During the three and six months ended June 30, 2014, $0.4 million and $0.3 million of expenses recognized related to claims, complaints and fines. During the three and six months ended June 30, 2013, expenses related to claims, complaints and fines were less than $0.1 million. As of June 30, 2014 and December 31, 2013, we have recorded $0.5 million and $0.2 million, respectively, which are included in Accrued liabilities on the Condensed Consolidated Balance Sheets, for the loss contingencies matters in the normal course of business.

12. Subsequent Events

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

13. Supplemental Guarantor Information

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

(1) in connection with any sale or other disposition of all or substantially all of the assets of a Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary (as such term is defined in the indenture governing the 8.50% Senior Notes) of the Company, if the sale or other disposition does not violate the “Asset Sales” provisions of the indenture;

(2) in connection with any sale or other disposition of the capital stock of such Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the “Asset Sales” provisions of the indenture and the Guarantor Subsidiary ceases to be a subsidiary of the Company as a result of such sales or disposition;

(3) if such Guarantor Subsidiary is a Restricted Subsidiary and the Company designates such Guarantor Subsidiary as an Unrestricted Subsidiary in accordance with the applicable provisions of the indenture;

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

(5) upon the liquidation or dissolution of such Guarantor Subsidiary, provided no event of default has occurred and is continuing; or

(6) at such time as such Guarantor Subsidiary is no longer required to be a Guarantor Subsidiary of the 8.50% Senior Notes as described in the indenture, provided no event of default has occurred and is continuing.

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of the Parent Company and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. Transfers of property, including related ARO, were made from the Parent Company to the Guarantor Subsidiaries to assist the Parent Company to continue to qualify for a waiver of certain supplemental bonding requirements from the BOEM. See Note 11 for additional information. As these transfers were transactions between entities under common control, the prior period financial information has been retrospectively adjusted for comparability purposes, as prescribed under authoritative guidance. These adjustments had no impact on the consolidated results for the current or prior periods presented.

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

Condensed Consolidating Balance Sheet as of June 30, 2014

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$23,847	$—	$—	$23,847
Receivables:				
Oil and natural gas sales	53,737	40,680	—	94,417
Joint interest and other	26,584	—	—	26,584
Income tax	144,976	—	(144,856)	120
Total receivables	225,297	40,680	(144,856)	121,121
Prepaid expenses and other assets	34,462	4,182	—	38,644
Total current assets	283,606	44,862	(144,856)	183,612
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,817,544	1,810,664	—	7,628,208
Furniture, fixtures and other	21,660	—	—	21,660
Total property and equipment	5,839,204	1,810,664	—	7,649,868
Less accumulated depreciation, depletion and amortization	4,295,168	1,030,906	—	5,326,074
Net property and equipment	1,544,036	779,758	—	2,323,794
Restricted deposits for asset retirement obligations	23,723	—	—	23,723
Other assets	1,160,693	566,950	(1,709,000)	18,643
Total assets	$3,012,058	$1,391,570	$(1,853,856)	$2,549,772
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$134,748	$5,747	$—	$140,495
Undistributed oil and natural gas proceeds	38,591	611	—	39,202
Asset retirement obligations	61,509	8,414	—	69,923
Accrued liabilities	59,800	116,355	(144,856)	31,299
Total current liabilities	294,648	131,127	(144,856)	280,919
Long-term debt, less current maturities	1,224,262	—	—	1,224,262
Asset retirement obligations, less current portion	172,999	114,681	—	287,680
Deferred income taxes	106,175	83,727	—	189,902
Other liabilities	660,588	—	(646,966)	13,622
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	410,641	842,802	(842,801)	410,642
Retained earnings	166,911	219,233	(219,233)	166,911

Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders’ equity	553,386	1,062,035	(1,062,034)	553,387
Total liabilities and shareholders’ equity	$ 3,012,058	$ 1,391,570	$ (1,853,856)	$ 2,549,772

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

Condensed Consolidating Balance Sheet as of December 31, 2013

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

Total liabilities and shareholders’ equity	$2,735,527	$1,274,834	$(1,503,059)	$2,507,302

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

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$162,071	$ 100,923	$ —	$ 262,994
Operating costs and expenses:				
Lease operating expenses	40,612	21,153	—	61,765
Production taxes	1,842	—	—	1,842
Gathering and transportation	2,218	1,767	—	3,985
Depreciation, depletion, amortization and accretion	71,327	56,909	—	128,236
General and administrative expenses	10,638	9,044	—	19,682
Derivative loss	13,079	—	—	13,079
Total costs and expenses	139,716	88,873	—	228,589
Operating income	22,355	12,050	—	34,405
Earnings of affiliates	7,939	—	(7,939)	—
Interest expense:				
Incurred	20,617	837	—	21,454
Capitalized	(1,322)	(837)	—	(2,159)
Income before income tax expense	10,999	12,050	(7,939)	15,110
Income tax expense (benefit)	1,162	4,111	—	5,273
Net income	$9,837	$ 7,939	$ (7,939)	$ 9,837

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$306,057	$ 211,453	$ —	$ 517,510
Operating costs and expenses:				
Lease operating expenses	79,724	37,660	—	117,384
Production taxes	3,834	—	—	3,834
Gathering and transportation	5,556	3,725	—	9,281
Depreciation, depletion, amortization and accretion	133,758	117,784	—	251,542
General and administrative expenses	22,083	21,187	—	43,270
Derivative loss	20,571	—	—	20,571

Total costs and expenses	265,526	180,356	—	445,882
Operating income	40,531	31,097	—	71,628
Earnings of affiliates	20,390	—	(20,390)	—
Interest expense:				
Incurred	41,294	1,618	—	42,912
Capitalized	(2,613)	(1,618)	—	(4,231)
Income before income tax expense	22,240	31,097	(20,390)	32,947
Income tax expense (benefit)	1,214	10,707	—	11,921
Net income	$21,026	$ 20,390	$ (20,390)	$ 21,026

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

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$147,070	$ 88,313	$ —	$ 235,383
Operating costs and expenses:				
Lease operating expenses	51,406	16,842	—	68,248
Production taxes	1,780	—	—	1,780
Gathering and transportation	2,833	1,775	—	4,608
Depreciation, depletion, amortization and accretion	55,706	44,190	—	99,896
General and administrative expenses	11,473	8,395	—	19,868
Derivative loss	(12,840)	—	—	(12,840)
Total costs and expenses	110,358	71,202	—	181,560
Operating income	36,712	17,111	—	53,823
Earnings of affiliates	11,143	—	(11,143)	—
Interest expense:				
Incurred	20,789	747	—	21,536
Capitalized	(1,785)	(747)	—	(2,532)
Income before income tax expense	28,851	17,111	(11,143)	34,819
Income tax expense	6,455	5,968	—	12,423
Net income	$22,396	$ 11,143	$ (11,143)	$ 22,396

Condensed Consolidating Statement of Income for the Six Months Ended June 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$317,611	$ 176,994	$ —	$ 494,605
Operating costs and expenses:				
Lease operating expenses	94,676	32,914	—	127,590
Production taxes	3,569	—	—	3,569
Gathering and transportation	5,112	3,940	—	9,052
Depreciation, depletion, amortization and accretion	118,908	89,859	—	208,767
General and administrative expenses	23,885	17,070	—	40,955
Derivative loss	(9,473)	—	—	(9,473)

Total costs and expenses	236,677	143,783	—	380,460
Operating income	80,934	33,211	—	114,145
Earnings of affiliates	21,641	—	(21,641)	—
Interest expense:				
Incurred	41,307	1,463	—	42,770
Capitalized	(3,501)	(1,463)	—	(4,964)
Income before income tax expense	64,769	33,211	(21,641)	76,339
Income tax expense	15,755	11,570	—	27,325
Net income	$49,014	$ 21,641	$ (21,641)	$ 49,014

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

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

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$21,026	$ 20,390	$ (20,390)	$ 21,026
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	133,758	117,784	—	251,542
Amortization of debt issuance costs and premium	366	—	—	366
Share-based compensation	7,644	—	—	7,644
Derivative loss	20,571	—	—	20,571
Cash payments on derivative settlements (realized)	(14,310)	—	—	(14,310)
Deferred income taxes	25,078	(13,157)	—	11,921
Earnings of affiliates	(20,390)	—	20,390	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	7,636	(5,301)	—	2,335
Joint interest and other receivables	3,550	—	—	3,550
Income taxes	(20,947)	23,865	—	2,918
Prepaid expenses and other assets	(127,910)	(86,875)	219,224	4,439
Asset retirement obligations settlements	(18,583)	(11,755)	—	(30,338)
Accounts payable, accrued liabilities and other	203,344	5,266	(219,224)	(10,614)
Net cash provided by operating activities	220,833	50,217	—	271,050
Investing activities:				
Acquisition of property interest in oil and natural gas properties	—	(53,363)	—	(53,363)
Investment in oil and natural gas properties and equipment	(157,128)	(55,552)	—	(212,680)
Investment in subsidiary	(58,698)	—	58,698	—
Purchases of furniture, fixtures and other	(1,715)	—	—	(1,715)
Net cash used in investing activities	(217,541)	(108,915)	58,698	(267,758)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	220,000	—	—	220,000
Repayments of long-term debt – revolving bank credit facility	(200,000)	—	—	(200,000)
Dividends to shareholders	(15,129)	—	—	(15,129)
Other	(116)	—	—	(116)
Investment from parent	—	58,698	(58,698)	—
Net cash provided (used) in financing activities	4,755	58,698	(58,698)	4,755

Increase in cash and cash equivalents	8,047	—	—	8,047
Cash and cash equivalents, beginning of period	15,800	—	—	15,800
Cash and cash equivalents, end of period	$23,847	$—	$—	$ 23,847

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

Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2013

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$49,014	$ 21,641	$ (21,641)	$ 49,014
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	118,908	89,859	—	208,767
Amortization of debt issuance costs and premium	910	—	—	910
Share-based compensation	4,950	—	—	4,950
Derivative gain	(9,473)	—	—	(9,473)
Cash payments on derivative settlements	(2,310)	—	—	(2,310)
Deferred income taxes	11,357	12,369	—	23,726
Earnings of affiliates	(21,641)	—	21,641	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	15,673	1,390	—	17,063
Joint interest and other receivables	38,635	—	—	38,635
Income taxes	9,378	(799)	—	8,579
Prepaid expenses and other assets	(26,487)	(27,054)	41,160	(12,381)
Asset retirement obligations	(29,740)	(3,146)	—	(32,886)
Accounts payable, accrued liabilities and other	44,054	(126)	(41,160)	2,768
Net cash provided by operating activities	203,228	94,134	—	297,362
Investing activities:				
Investment in oil and natural gas properties and equipment	(205,079)	(94,134)	—	(299,213)
Purchases of furniture, fixtures and other	(981)	—	—	(981)
Net cash used in investing activities	(206,060)	(94,134)	—	(300,194)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	252,000	—	—	252,000
Repayments of long-term debt – revolving bank credit facility	(239,000)	—	—	(239,000)
Dividends to shareholders	(12,795)	—	—	(12,795)
Other	(342)	—	—	(342)
Net cash used in financing activities	(137)	—	—	(137)
Increase in cash and cash equivalents	(2,969)	—	—	(2,969)
Cash and cash equivalents, beginning of period	12,245	—	—	12,245
Cash and cash equivalents, end of period	$9,276	$ —	$ —	$ 9,276

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

The following discussion and analysis should be read in conjunction with our accompanying unaudited condensed consolidated financial statements and the notes to those financial statements included in Item 1 of this Quarterly Report on Form 10-Q. The following discussion contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 ("the "Exchange Act"), which involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Known material risks that may affect our financial condition and results of operations are discussed in Item 1A, Risk Factors, and market risks are discussed in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, of our Annual Report on Form 10-K for the year ended December 31, 2013 and may be discussed or updated from time to time in subsequent reports filed with the SEC. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We assume no obligation, nor do we intend, to update these forward-looking statements. Unless the context requires otherwise, references in this Quarterly Report on Form 10-Q to "W&T," "we," "us," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries and references to "Parent Company" are solely to W&T Offshore, Inc.

Overview

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

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for the six months ended June 30, 2014 were comprised of 41.0% oil and condensate, 11.8% NGLs and 47.2% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel oil equivalent ("Boe") for oil, NGLs and natural gas may differ significantly. In the six months ended June 30, 2014, revenues from the sale of oil and NGLs made up 76.7% of our total revenues compared to 80.9% in the same period of 2013. For the six months ended June 30, 2014, our combined total production of oil, condensate, NGLs and natural gas was 1.5% higher on a Boe basis than during the same period in 2013. Over that same time frame, our total revenues were 4.6% higher, driven primarily by higher oil production and higher natural gas prices, partially offset by lower oil prices. See sections Results of Operations – Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013; and Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013 for additional information on our revenues and production.

In May 2014, we acquired from Woodside certain oil and natural gas property interests in the Gulf of Mexico. The Woodside Properties consisted of a 20% non-operated working interest in the producing Neptune field (deepwater Atwater Valley blocks 574, 575 and 618), along with an interest in associated production facilities and various interests in 24 other deepwater blocks in the Gulf of Mexico. Operating results for the Woodside Properties are included in our results since the closing date of May 20, 2014. The results for the three and six months ended June 30, 2013 do not include the Woodside Properties' operations as this period precedes the acquisition date. See Part I, Item 1, Financial Statements - Note 2 - Acquisitions and Divestitures, for additional information.

In November and December 2013, we acquired from Callon certain oil and gas leasehold interests in the Gulf of Mexico. The Callon Properties consist of a 15% working interest in the Medusa field (deepwater Mississippi Canyon blocks 582 and 583), interest in associated production facilities and various interests in other non-operated fields. The operating results of the Callon Properties are included in our results for the three and six months ended June 30, 2014. The results for the three and six months ended June 30, 2013 do not include the Callon Properties' operations as this period precedes the acquisition date. See Part I, Item 1, Financial Statements - Note 2 - Acquisitions and Divestitures, for additional information.

Our operating results are strongly influenced by the price of the commodities that we produce and sell. The price of those commodities is affected by both domestic and international factors, including domestic production, and the ability of the industry to get production to market. The infrastructure to transport crude oil within the United States has seen a major change over the past few years. A number of pipelines have been built and completed, reversed flowed, or expanded to move crude oil from Cushing, Oklahoma (a major crude oil storage hub) primarily to the U.S. Gulf Coast but also to the Midwest as well. Transportation capacity has also been added in major producing regions like the Permian Basin to move crude oil to the U.S. Gulf Coast rather than to Cushing. Both of these events have helped relieve the excess crude oil that built up in Cushing (inventories have decreased from a high of over 50 million barrels to a low of 20 million barrels over the last year), which in turn allowed WTI pricing to increase relative to Brent up to the fourth quarter of 2013. Beginning in the fourth quarter of 2013 and continuing during the first half of 2014, the premiums for the Gulf of Mexico crude oil have declined as the crude being moved to the U.S. Gulf Coast increased and imports continued. The structural changes that have occurred as a result of new pipeline and rail infrastructure are expected to impact U.S. Gulf Coast crude oil pricing going forward. During the second quarter of 2014, premiums for Light Louisiana Sweet ("LLS") and Heavy Louisiana Sweet ("HLS") relative to WTI reverted to more historical levels and some Gulf Coast crudes traded at a discount to WTI as a result of the pricing competition that is now present on the Gulf Coast. Rail receiving capacity has also been expanding rapidly on the East Coast and to some extent on the U.S. Gulf Coast with more capacity being announced. The average spread between Brent and WTI was approximately 40% lower during the first half of 2014 compared to the first half of 2013 as a result of the increased domestic production and structural changes outlined above.

During the first half of 2014, our average realized oil sales price was very strong by historical standards but was 5.1% lower than that realized in the same period of 2013 even though both benchmark crudes discussed below were higher priced in the 2014 period compared to the 2013 period. WTI increased to $101.05 per barrel from $94.18 per barrel between the first half of 2014 and the first half of 2013. In addition, Brent prices increased to $108.93 per barrel from $107.27 per barrel for this same time frame, as reported by the U.S. Energy Information Administration ("EIA"). WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. Over 85% of our oil is produced from offshore in the Gulf of Mexico and is characterized as LLS, HLS, Poseidon and others. Over the past several years, we had been realizing very strong premiums on our Gulf Coast crudes, but these premiums decreased significantly beginning in the fourth quarter of 2013 and continued at lower levels during the first half of 2014. For example, the premiums for LLS and HLS for the first half of 2014 ranged from $4.00 to $10.00 per barrel above WTI compared to $10.00 to $22.00 per barrel for the first half of 2013. More impactful was the change in the pricing of Poseidon crude which traded at a discount to WTI in the first half of 2014 compared to a significant premium in the 2013 period. Permian crudes also have been trading at a discount to WTI and likely will continue to do so until the pipeline and rail capacity that has been announced is constructed and put in to service. In addition, our oil production in West Texas incurs discounts for transportation costs incurred by the purchaser, with larger discounts applied where the oil is trucked due to lack of pipeline access. The above factors caused the decrease of our average realized oil sales price in the first half of 2014 when compared to the first half of 2013.

Oil prices are heavily influenced by world economic and political events, such as political unrest in the Middle East and Ukraine, the threat of hostilities around the world, demand changes in various countries and world economic growth. Thus, crude oil prices will likely continue to be volatile. For the first half of 2014, WTI crude oil prices ranged from $91.00 to $108.00 per barrel and Brent crude oil prices ranged from $103.00 to $115.00 per barrel. The EIA estimates that the average WTI crude spot price was $101.00 per barrel during the first half of 2014 and will be $101.00 per barrel for all of 2014 and $95.00 per barrel in 2015. EIA estimates the average Brent crude oil spot price was $109.00 per barrel during the first half of 2014 and projects the average price to be $109.00 for all of 2014 and $105.00 per barrel in 2015. The EIA projected 2014-2015 prices for both WTI and Brent have been increased from their projections made in April 2014. EIA expects world-wide supply and consumption for oil and other types of liquid fuels to be fairly equal for 2014 and 2015, resulting in minor inventory withdrawals or builds. Production is expected to increase in the 2014-2015 timeframe primarily from the United States and Canada. Consumption is expected to increase in 2014 and 2015 primarily in China and other Asian countries.

Our average realized NGLs sales prices increased 17.6% during the first half of 2014 versus the comparable 2013 period. The two major components of our NGLs are ethane and propane, which typically make up over 70% of a NGL barrel. During the first half of 2014, prices for domestic ethane increased 24% and domestic propane prices increased 33% from the comparable 2013 period. Price changes for other domestic NGLs ranged from a decrease of 7% to an increase of 1%. Colder weather was a major factor in the increase of the price of propane. Other market factors influenced the temporary increase in the price of ethane, as it is not used directly as a heating fuel. However, cold weather drove up the price of natural gas, helping to increase the price of ethane, which is extracted from natural gas. Once the cold weather passed, ethane prices declined to pre-winter pricing but are still above the second quarter of 2013. As long as the price ratio of crude oil to natural gas remains wide (as measured on a six to one energy equivalency), the production of NGLs may continue to be high relative to historical norms and would, in turn, suggest downward price pressure on the price of ethane. Many natural gas processing facilities are re-injecting ethane back into the natural gas stream after processing due to insufficient ethane demand. The re-injection of ethane into the natural gas stream increases natural gas supplies and prevents natural gas prices from rising.

Prices for natural gas in the U.S. improved during the first half of 2014 versus the comparable 2013 period largely due to above-average storage withdrawals in response to the colder winter weather in 2014 and higher industrial demand. The amount of heating degree days for the winter was 13% higher than last year, which was a primary causal factor for the increased demand. Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. During the first half of 2014, the average realized sales price for our natural gas production increased 27.5% from the comparable 2013 period to $4.82 per Mcf. A comparable benchmark is the Henry Hub unweighted average daily posted spot price, which increased 30.1% from the comparable period. Average realized prices decreased in the second quarter of 2014 compared to the first quarter of 2014, but were still higher than the second quarter of 2013.

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

Per EIA, natural gas working inventories at the end of the first half of 2014 were estimated at 1,985 billion cubic feet (“Bcf”), which is 25% below the comparable 2013 period. EIA estimates the Henry Hub natural gas spot price was $4.91 per million British thermal unit (“MMBtu”) in the first half of 2014 and forecasts $4.77 per MMBtu for all of 2014 and $4.50 per MMBtu in 2015. Even with the colder winter, EIA projects U.S. supply to be higher than consumption for both 2014 and 2015.

According to Baker Hughes, the U.S. natural gas rig count was 439 at the beginning of 2013. The natural gas rig count decreased during 2013 to 372 rigs at the end of 2013 and decreased further to 311 at the end of June 2014, which is a 21 year low. Despite the decline in rigs drilling specifically for natural gas, the U.S. has experienced a year over year increase in natural gas production due to the many factors previously enumerated. Oil wells have increased natural gas production as a by-product, with the number of rigs searching for oil increasing from 1,318 at the beginning of 2013 to 1,378 at the end of 2013, and further increasing to 1,562 as of the end of June 2014. In the Gulf of Mexico, there were 48 rigs (29 oil, 19 natural gas) at the beginning of 2013, 59 rigs (39 oil, 20 natural gas) at the end of 2013 and 53 rigs (41 oil and 12 natural gas) as of the end of June 2014. EIA estimates the percentage of electricity fueled by natural gas to be 25% in the first half of 2014 compared to 26% in the first half of 2013, and forecasts the percentage at 27% for all of 2014 and 28% in 2015, influenced largely by the expected price of natural gas compared to the expected price of coal. Industry sources have indicated that a natural gas price above $4.50 per Mcf for some period of time will probably cause even more power producers to switch back to coal from natural gas, which in effect creates limits to how far natural gas prices can rise until such time as demand for natural gas increases from other sources. The demand for natural gas is expected to continue to increase as the announced petrochemical facilities are constructed and power producers convert to consuming natural gas to reduce emissions to ever tighter emission regulations and standards. Several companies are planning to build liquefaction capacity to export liquefied natural gas due to significantly higher natural gas prices in Europe and Asia with one such plant having been announced to come online in 2015.

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

As reported and discussed in more detail in Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q, W&T Offshore, Inc., the Parent Company, received a Notice of Suspension and Proposed Debarment and a Notice of Clean Water Act Listing from the EPA. The Notices applied to the Parent Company but were not directed to our wholly-owned subsidiaries. Accordingly, under the current scope of the Notices, the drilling and leasing operations of our wholly-owned subsidiary, Energy VI, had not been materially impacted by the debarment and suspension, nor was the Parent Company's drilling, exploration and production operations impacted on its existing Federal leases. On August 5, 2014, the EPA lifted the suspension and proposed debarment, which is discussed in more detail in Part I, Item 1, Financial Statements – Note 12 – Subsequent Events, of this Form 10-Q.

Also as reported and discussed in more detail in Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q, we received notice in May 2014 from the BOEM that reinstitutes the Parent Company's eligibility for a waiver of certain supplemental bonding for potential offshore decommissioning, plugging and abandonment liabilities. The notice applies to the Parent Company only. Our wholly-owned subsidiary, Energy VI, continues to require supplemental bonding for potential offshore decommissioning, plugging and abandonment liabilities.

As described in Part I, Item 1, Financial Statements – Note 1 – Basis of Presentation, of this Form 10-Q, in the fourth quarter of 2013, we identified that we had been receiving an erroneous conversion factor from a third party that had the effect of understating natural gas production in prior periods. The amounts included in the adjustment recognized in the fourth quarter 2013 period which relate to the three and six months ended June 30, 2013 were: an increase in natural gas production volumes of 254 MMcf and 518 MMcf, respectively (with no corresponding increase in revenue); an increase in DD&A expense of $0.7 million and $1.5 million, respectively; and a decrease in net income of $0.5 million and $1.0 million, respectively. The additional volumes would have revised average realized prices to $56.64 per Boe from the reported $57.22 per Boe for the six months ended June 30, 2013.

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

The Fifth Circuit reversed a lower court's ruling that the insurance underwriters did not have to reimburse us our costs for removal of wreck related to damages we incurred during Hurricane Ike. As the limits of the Energy Package have been exhausted, we have filed or anticipate filing claims of up to approximately $46.3 million under the Excess Policies and ultimately expect to receive recovery of claims. See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for additional information.

Results of Operations

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014(1)	2013	Change	%	2014(1)	2013	Change	%
	(In thousands, except percentages and per share data)				(In thousands, except percentages and per share data)			
Financial:								
Revenues:								
Oil	$185,424	$168,678	$16,746	9.9 %	$356,129	$366,242	$(10,113)	(2.8)%
NGLs	20,566	15,800	4,766	30.2 %	40,588	34,127	6,461	18.9 %
Natural gas	56,105	49,994	6,111	12.2 %	119,442	92,932	26,510	28.5 %
Other	899	911	(12)	(1.3)%	1,351	1,304	47	3.6 %
Total revenues	262,994	235,383	27,611	11.7 %	517,510	494,605	22,905	4.6 %
Operating costs and expenses:								
Lease operating expenses	61,765	68,248	(6,483)	(9.5)%	117,384	127,590	(10,206)	(8.0)%
Production taxes	1,842	1,780	62	3.5 %	3,834	3,569	265	7.4 %
Gathering and transportation	3,985	4,608	(623)	(13.5)%	9,281	9,052	229	2.5 %
Depreciation, depletion, amortization and accretion	128,236	99,896	28,340	28.4 %	251,542	208,767	42,775	20.5 %
General and administrative expenses	19,682	19,868	(186)	(0.9)%	43,270	40,955	2,315	5.7 %
Derivative (gain) loss	13,079	(12,840)	25,919	NM	20,571	(9,473)	30,044	NM
Total costs and expenses	228,589	181,560	47,029	25.9 %	445,882	380,460	65,422	17.2 %
Operating income	34,405	53,823	(19,418)	(36.1)%	71,628	114,145	(42,517)	(37.2)%
Interest expense, net of amounts capitalized	19,295	19,004	291	1.5 %	38,681	37,806	875	2.3 %
Income before income tax expense	15,110	34,819	(19,709)	(56.6)%	32,947	76,339	(43,392)	(56.8)%
Income tax expense	5,273	12,423	(7,150)	(57.6)%	11,921	27,325	(15,404)	(56.4)%
Net income	$9,837	$22,396	$(12,559)	(56.1)%	$21,026	$49,014	$(27,988)	(57.1)%
Basic and diluted earnings per common share	$0.13	$0.29	$(0.16)	(55.2)%	$0.28	$0.64	$(0.36)	(56.3)%

(1) In the second quarter of 2014, we acquired the Woodside Properties and in the fourth quarter of 2013, we acquired the Callon Properties.

NM – not meaningful

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014[1]	2013	Change	%[3]	2014[1]	2013	Change	%3)
Operating:								
Net sales:								
Oil (MBbls)	1,856	1,657	199	12.0 %	3,588	3,501	87	2.5 %
NGLs (MBbls)	514	491	23	4.7 %	1,038	1,026	12	1.2 %
Natural gas (MMcf)	12,150	11,842	308	2.6 %	24,768	24,562	206	0.8 %
Total oil equivalent (MBoe) [2]	4,395	4,122	273	6.6 %	8,754	8,621	133	1.5 %
Total natural gas equivalents (MMcfe) [2]	26,371	24,733	1,638	6.6 %	52,521	51,726	795	1.5 %
Average daily equivalent sales (Boe/day) [2]	48,299	45,298	3,001	6.6 %	48,362	47,630	732	1.5 %
Average daily equivalent sales (Mcfe/day) [2]	289,792	271,786	18,006	6.6 %	290,174	285,779	4,395	1.5 %
Average realized sales prices:								
Oil ($/Bbl)	$99.92	$101.78	$(1.86)	(1.8)%	$99.26	$104.61	$(5.35)	(5.1)%
NGLs ($/Bbl)	39.98	32.17	7.81	24.3 %	39.11	33.26	5.85	17.6%
Natural gas ($/Mcf)	4.62	4.22	0.40	9.5 %	4.82	3.78	1.04	27.5%
Oil equivalent ($/Boe) [2]	59.63	56.88	2.75	4.8 %	58.97	57.22	1.75	3.1 %
Natural gas equivalent ($/Mcfe) [2]	9.94	9.48	0.46	4.9 %	9.83	9.54	0.29	3.0 %
Average per Boe ($/Boe) [2]:								
Lease operating expenses	$14.05	$16.56	$(2.51)	(15.2)%	$13.41	$14.80	$(1.39)	(9.4)%
Gathering and transportation	0.91	1.12	(0.21)	(18.8)%	1.06	1.05	0.01	1.0 %
Production costs	14.96	17.68	(2.72)	(15.4)%	14.47	15.85	(1.38)	(8.7)%
Production taxes	0.42	0.43	(0.01)	(2.3)%	0.44	0.41	0.03	7.3 %
DD&A	29.18	24.23	4.95	20.4 %	28.73	24.22	4.51	18.6%
General and administrative expenses	4.48	4.82	(0.34)	(7.1)%	4.94	4.75	0.19	4.0 %
	$49.04	$47.16	$1.88	4.0 %	$48.58	$45.23	$3.35	7.4 %
Average per Mcfe ($/Mcfe) [2]:								
Lease operating expenses	$2.34	$2.76	$(0.42)	(15.2)%	$2.23	$2.47	$(0.24)	(9.7)%
Gathering and transportation	0.15	0.19	(0.04)	(21.1)%	0.18	0.17	0.01	5.9 %
Production costs	2.49	2.95	(0.46)	(15.6)%	2.41	2.64	(0.23)	(8.7)%
Production taxes	0.07	0.07	-	0.0 %	0.07	0.07	-	0.0 %
DD&A	4.86	4.04	0.82	20.3 %	4.79	4.04	0.75	18.6%
General and administrative expenses	0.75	0.80	(0.05)	(6.3)%	0.82	0.79	0.03	3.8 %
	$8.17	$7.86	$0.31	3.9 %	$8.09	$7.54	$0.55	7.3 %

(1) In the second quarter of 2014, we acquired the Woodside Properties and in the fourth quarter of 2013, we acquired the Callon Properties.

(2) The conversions to barrels of oil equivalent and cubic feet equivalent were determined using the energy equivalency ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price on an equivalent basis for oil, NGLs and natural gas may differ significantly.

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

Volume measurements:

Boe - barrel of oil equivalent	Mcfe - thousand cubic feet equivalent
Boe/d - barrel of oil equivalent per day	Mcfe/d - thousand cubic feet equivalent per day
MBbls - thousand barrels for crude oil, condensate or NGLs	MMcf - million cubic feet
MBoe - thousand barrels of oil equivalent	MMcfe - million cubic feet equivalent

	Three Months Ended June 30, 2014	2013	Change	%	Six Months Ended June 30, 2014	2013	Change	%
Wells drilled (gross):								
Offshore	1	1	—	—	3	3	—	—
Onshore	12	9	3	33.3%	22	23	(1)	(4.3)%
Productive wells drilled (gross)								
Offshore	1	1	—	—	3	2	1	50.0%
Onshore	12	9	3	33.3%	21	23	(2)	(8.7)%

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

Revenues. Total revenues increased $27.6 million to $263.0 million for the second quarter of 2014 as compared to the same period in 2013. Oil revenues increased $16.7 million, or 9.9%, NGLs revenues increased $4.8 million, or 30.2%, natural gas revenues increased $6.1 million, or 12.2%, and other revenues were flat. The oil revenue increase was attributable to a 12.0% increase in sales volumes, partially offset by a 1.8% decrease in the average realized sales price to $99.92 per barrel for the second quarter of 2014 from $101.78 per barrel for the prior year period. The NGLs revenue increase was attributable to a 24.3% increase in the average realized sales price to $39.98 per barrel for the second quarter of 2014 from $32.17 per barrel for the prior year period and from an increase of 4.7% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 9.5% increase in the average realized natural gas sales price to $4.62 per Mcf in the second quarter of 2014 from $4.22 per Mcf for the prior year period and from an increase of 2.6% in sales volumes from the comparable period. We experienced increases in production from the new A-5 well at Mississippi Canyon 243 (Matterhorn), the A-14 well at Ship Shoal 349 (Mahogany), the acquisition of the Callon Properties and the acquisition of the Woodside Properties. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestitures of certain fields in 2013. Production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 0.6 million barrels of oil equivalent ("MMBoe") during the second quarter of 2014. Specifically, production at Mississippi Canyon 506 (Wrigley) continues to be deferred as a result of maintenance at Shell's Cognac platform and comprised approximately 30% of the deferred production. Production from selected wells at Ship Shoal 349 (Mahogany) was deferred primarily due to rig moves and well work. The balance of the deferred production occurred at multiple locations. During the second quarter of 2013, we experienced production deferrals of 0.5 MMBoe, which included the continued pipeline outage at Mississippi Canyon 506 (Wrigley).

Revenues from oil and liquids as a percent of our total revenues were 78.3% for the second quarter of 2014 compared to 78.4% for the comparable 2013 period. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 40.0% for the second quarter of 2014 compared to 31.6% for the comparable 2013 period.

Lease operating expenses. Lease operating expenses, which includes base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, and hurricane related expenses and insurance reimbursements, decreased $6.5 million to $61.8 million in the second quarter of 2014 compared to the prior year period. On a per Boe basis, lease operating expenses decreased to $14.05 per Boe during the second quarter of 2014 compared to $16.56 per Boe during the comparable 2013 period. On a component basis, workovers decreased $16.2 million and insurance premiums decreased $1.2 million. The decrease in workover costs was primarily due to a rig workover at Main Pass 69 in the second quarter of 2013. There were no costs incurred of this nature during the second quarter of 2014. Partially offsetting the decrease in workover costs were increases in base lease operating expenses of $9.7 million and facilities maintenance of $1.2 million. Base lease operating expenses were higher due to more downhole well work in our West Texas onshore operations, higher expenses offshore and increased contract labor.

Production taxes. Production taxes increased $0.1 million to $1.8 million in the second quarter of 2014 compared to the prior year period primarily due to onshore activities and are currently not a large component of our operating costs. Most of our production is from federal waters where no production taxes are imposed, whereas onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased $0.6 million to $4.0 million for the second quarter of 2014 compared to the prior year period.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $29.18 per Boe for the second quarter of 2014 from $24.23 per Boe in the prior year period. On a nominal basis, DD&A increased to $128.2 million for the second quarter of 2014 from $99.9 million in the prior year period. DD&A on a per Boe basis and nominal basis increased in part due to increases in the full cost pool from capital expenditures and estimated future development costs. The focus on expanding our deepwater exploration and development necessarily increases costs before increasing proved reserves, leading to an increase in the rate.

General and administrative expenses. G&A decreased to $19.7 million for the second quarter of 2014 from $19.9 million for the prior year period primarily due to decreases in surety bond fees from timing of payments and partially offset by increases in share-based compensation. G&A on a per Boe basis was $4.48 per Boe for the second quarter of 2014, compared to $4.82 per Boe for the prior year period.

Derivative (gain) loss. For the second quarter of 2014 and 2013, our derivative positions resulted in a net loss of $13.1 million and a net gain of $12.8 million, respectively, and relate to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices. Although the open contracts relate to production for future periods, changes in the fair value for all open contracts are recorded at the end of the respective reporting period. For the second quarter of 2014, the net loss was comprised of a $9.7 million realized loss and a $3.4 million unrealized loss. For the second quarter of 2013, the net gain consisted of a realized gain of $1.9 million and an unrealized gain of $10.9 million. For additional information about our derivatives, refer to Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q.

Interest expense. Interest expense incurred was essentially flat at $21.5 million for the second quarter of 2014 and 2013. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both the second quarter of 2014 and 2013. During the second quarter of 2014 and 2013, $2.2 million and $2.5 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying certain unevaluated properties to the full cost pool during the fourth quarter of 2013.

Income tax expense. Income tax expense was $5.3 million for the second quarter of 2014 compared to $12.4 million for the same period of 2013 with the decrease primarily attributable to lower pre-tax income. Our effective tax rate for the second quarter of 2014 was 34.9% and differed from the federal statutory rate of 35.0% primarily as a result of adjustments to a revised full-year forecasted rate. Our effective tax rate for the second quarter of 2013 was 35.7% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes.

Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

Revenues. Total revenues increased $22.9 million to $517.5 million for the first half of 2014 as compared to the same period in 2013. Oil revenues decreased $10.1 million, or 2.8%, NGLs revenues increased $6.5 million, or 18.9%, natural gas revenues increased $26.5 million, or 28.5%, and other revenues were flat. The oil revenue decrease was attributable to a 5.1% decrease in the average realized sales price to $99.26 per barrel for the first half of 2014 from $104.61 per barrel for the prior year period, partially offset by a 2.5% increase in sales volumes. The NGLs revenue increase was attributable to a 17.6% increase in the average realized sales price to $39.11 per barrel for the first half of 2014 from $33.26 per barrel for the prior year period and from an increase of 1.2% in sales volumes from the comparable period. The increase in natural gas revenue resulted from a 27.5% increase in the average realized natural gas sales price to $4.82 per Mcf in the first half of 2014 from $3.78 per Mcf for the prior year period and from an increase of 0.8% in sales volumes from the comparable period. We experienced increases in production from the new A-5 well at Mississippi Canyon 243 (Matterhorn), the A-14 well at Ship Shoal 349 (Mahogany) and the acquisition of the Callon Properties and the acquisition of the Woodside Properties. Production was negatively impacted for all commodities from natural production declines, production deferrals affecting various fields and the divestitures of certain fields in 2013. The production deferrals were attributable to third-party pipeline outages, platform maintenance, and various operational issues. We estimate production deferrals were 1.2 MMBoe during the first half of 2014. Specifically, production at Mississippi Canyon 506 (Wrigley) continues to be deferred as a result of maintenance at Shell's Cognac platform and comprised approximately 28% of the deferred production. Production from selected wells at Ship Shoal 349 (Mahogany) was deferred due to closure of a pipeline, a rig move and well work. In addition, weather was a contributing factor in the first quarter of 2014 for production declines at West Texas and at selected offshore fields. The balance of the deferred production occurred at multiple locations. During the first half of 2013, we experienced production deferrals of 0.8 MMBoe, which included the continued pipeline outage at

Mississippi Canyon 506 (Wrigley).

Revenues from oil and liquids as a percent of our total revenues were 76.7% for the first half of 2014 compared to 80.9% for the comparable 2013 period. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 39.4% for the first half of 2014 compared to 31.8% for the comparable 2013 period.

Lease operating expenses. Lease operating expenses, which includes base lease operating expenses, insurance premiums, workovers and maintenance on our facilities, and hurricane related expenses and insurance reimbursements, decreased $10.2 million to $117.4 million in the first half of 2014 compared to the prior year period. On a per Boe basis, lease operating expenses decreased to $13.41 per Boe during the first half of 2014 compared to $14.80 per Boe during the comparable 2013 period. On a component basis, workovers decreased $15.9 million, insurance premiums decreased $3.3 million and hurricane related expenses and insurance reimbursements decreased by $0.8 million. The decrease in workover costs was primarily due to a rig workover at Main Pass 69 in the first half of 2013. There were no costs incurred of this nature during the first half of 2014. Partially offsetting the decrease in workover costs were increases in base lease operating expenses of $9.3 million and facilities maintenance of $0.5 million. Base lease operating expenses were higher due to more downhole well work in our West Texas onshore operations, higher expenses offshore and increased contract labor.

Production taxes. Production taxes increased $0.3 million to $3.8 million in the first half of 2014 compared to the prior year period primarily due to onshore activities and are currently not a large component of our operating costs. Most of our production is from federal waters where no production taxes are imposed, whereas onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.3 million to $9.3 million for the first half of 2014 compared to the prior year period primarily due to escalation in third-party transportation fees.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, increased to $28.73 per Boe for the first half of 2014 from $24.22 per Boe in the prior year period. On a nominal basis, DD&A increased to $251.5 million for the first half of 2014 from $208.8 million in the prior year period. DD&A on a per Boe basis and nominal basis increased in part due to increases in the full cost pool from capital expenditures and estimated future development costs. The focus on expanding our deepwater exploration and development necessarily increases costs before increasing proved reserves, leading to an increase in the rate.

General and administrative expenses. G&A increased to $43.3 million for the first half of 2014 from $41.0 million for the prior year period primarily due to increases in surety bond fees, contract labor and professional fees and compensation costs. G&A on a per Boe basis was $4.94 per Boe for the first half of 2014, compared to $4.75 per Boe for the prior year period.

Derivative (gain) loss. For the first half of 2014 and 2013, our derivative positions resulted in a net loss of $20.6 million and a net gain of $9.5 million, respectively, and relate to the change in the fair value of our crude oil commodity derivatives as a result of changes in crude oil prices. Although the open contracts relate to production for future periods, changes in the fair value for all open contracts are recorded at the end of the respective reporting period. For the first half of 2014, the net loss was comprised of a $14.3 million realized loss and a $6.3 million unrealized loss. For the first half of 2013, the net gain consisted of a realized loss of $2.3 million and an unrealized gain of $11.8 million. For additional information about our derivatives, refer to Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q.

Interest expense. Interest expense incurred increased slightly by $0.1 million to $42.9 million for the first half of 2014 compared to the prior year period. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both the first half of 2014 and 2013. During the first half of 2014 and 2013, $4.2 million and $5.0 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties. The decrease is primarily attributable to reclassifying certain unevaluated properties to the full cost pool during the fourth quarter of 2013.

Income tax expense. Income tax expense was $11.9 million for the first half of 2014 compared to $27.3 million for the same period of 2013 with the decrease primarily attributable to lower pre-tax income. Our effective tax rate for the first half of 2014 was 36.2% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes and other permanent items. Our effective tax rate for the first half of 2013 was 35.8% and differed from the federal statutory rate of 35.0% primarily as a result of state income taxes.

Liquidity and Capital Resources

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

Cash flow and working capital. Net cash provided by operating activities for the six months ended June 30, 2014 was $271.1 million compared to $297.4 million for the comparable 2013 period. Cash flows from operating activities, before changes in working capital and ARO settlements, were $298.8 million in the first six months of 2014, an increase of $23.2 million compared to the $275.6 million generated over the same time period in 2013 driven by higher revenues and lower operating expenses. Our combined average realized sales price per Boe was 3.1% higher than in the comparable 2013 period due to higher average realized natural gas and NGL's sales prices. Our combined production of oil, NGLs and natural gas on a Boe basis during the six months ended June 30, 2014 increased 1.5% from the comparable 2013 period. The change in working capital and ARO settlements between periods was a usage of $49.5 million. The change in working capital was primarily due to changes in receivables, where at the beginning of 2013, receivable balances were higher than historical trends and led to higher than normal collections in the first half of 2013. For 2014, receivable balances from the beginning of the year through the first half of 2014 have been fairly constant. An additional item for working capital changes was the receipt of funds in the first half of 2014 related to an arrangement involving escrowed deposits. Escrowed deposits are included within Prepaid and Other Assets on the statement of cash flows.

Net cash used in investing activities during the six months ended June 30, 2014 and 2013 was $267.8 million and $300.2 million, respectively, which represents our investments in both offshore and onshore oil and gas properties. The decrease is primarily attributable to decreases in both onshore and offshore drilling and development activities, partially offset by the purchase of the Woodside Properties in 2014. There were no acquisitions or divestitures of significance completed in the comparable 2013 period.

Net cash provided by financing activities was $4.8 million during the six months ended June 30, 2014 and net cash used in financing activities was $0.1 million for the six months ended June 30, 2013. The net cash provided during the six months ended June 30, 2014 was primarily attributable to net borrowings on our revolving bank credit facility of $20.0 million and partially offset by dividend payments of $15.1 million. The purchase of the Woodside properties was partially funded through borrowings on the revolving bank credit facility. The net cash used in the six months ended June 30, 2013 was essentially flat with dividend payments offset by $13.0 million of net borrowings on our revolving bank credit facility.

At June 30, 2014, we had a cash balance of $23.8 million and $439.4 million of undrawn capacity available under the revolving bank credit facility, which had a borrowing base of $750.0 million.

Credit Agreement and long-term debt. At June 30, 2014 and December 31, 2013, $310.0 million and $290.0 million, respectively, were outstanding under our revolving bank credit facility. During the six months ended June 30, 2014, the outstanding borrowings on our revolving bank credit facility ranged from $242.0 million to $334.0 million. At June 30, 2014 and December 31, 2013, $900.0 million in aggregate principal amount of our 8.50% Senior Notes was outstanding. We believe that cash provided by operations, borrowings available under our revolving bank credit facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements, but additional financing could be required if we are successful in finding suitable acquisitions and for future development activities. For additional information about our long-term debt, refer to Part I, Item 1, Financial Statements – Note 5 – Long-Term Debt, of this Form 10-Q.

Availability under our revolving bank credit facility is subject to a semi-annual redetermination of our borrowing base that occurs in the spring and fall of each year and is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. The Credit Agreement contains financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement and all applicable covenants related to the 8.50% Senior Notes as of June 30, 2014.

Derivatives. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of our oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of June 30, 2014, our derivative instruments outstanding consisted of oil contracts relating to approximately 1.7 million barrels ("MMBbls") of our anticipated production for the balance of 2014. See Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q for additional information.

Insurance Claims and Insurance Coverage. During 2008, Hurricane Ike caused substantial property damage. Substantially all the costs related to Hurricane Ike have been incurred and we submitted claims under our insurance policies effective at that time, of which $151.2 million has been collected through June 30, 2014. We received a ruling in our favor from the United States Court of Appeals for the Fifth Circuit concerning the underwriters' interpretation of our Excess Policies related to the coverage of removal-of-wreck costs incurred due to Hurricane Ike. The underwriters filed three separate briefs requesting a rehearing or a certification to the Texas Supreme Court, all of which the Court denied. As the limits of the Energy Package have been exhausted, we have filed and anticipate filing claims of up to approximately $46.3 million under the Excess Policies and ultimately expect to receive recovery of claims. Removal-of-wreck costs and insurance recoveries related to removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Balance Sheets. See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for additional information.

We currently carry multiple layers of insurance coverage in our Energy Package covering our operating activities, with higher limits of coverage for higher valued properties and wells. The current policy limits for well control range from $30.0 million to $500.0 million depending on the risk profile and contractual requirements. We have $75.0 million of named windstorm (hurricane and tropical storm) coverage for certain of our offshore properties and wells and an additional $75.0 million for certain properties and wells at our higher value fields. We have $50.0 million of named windstorm coverage for our lower value offshore properties for the cost of removal in excess of scheduled ARO amounts. The well control, named windstorm and physical damage coverage is effective until June 1, 2015. A per-occurrence retention amount of $30.0 million for named windstorm events must be satisfied by us before our insurers will indemnify us for losses and we co-insure 15% of our named windstorm coverage. We also have other smaller per-occurrence retention amounts for various other events. Coverage for pollution causing a negative environmental impact is provided under the well control and named windstorm sections of the policy.

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

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

Although we were able to renew our Energy Package and our general and excess liability policies in the second quarter of 2014 and have not been informed otherwise, in the future, our insurers may not continue to offer this type and level of coverage to us, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for information related to notifications from the BOEM concerning supplemental bonding requirements

Capital expenditures. The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors, including the prices of oil, NGLs and natural gas, acquisition opportunities, and the results of our exploration and development activities. The following table presents our capital expenditures for exploration, development and other leasehold costs and acquisitions:

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Acquisition of Woodside Properties	$53,363	$—
Acquisition of Callon Properties (1)	576	—

Exploration (2)	86,793	109,283
Development (2)	104,685	168,116
Seismic, capitalized interest, other leasehold costs interest, other leasehold costs	20,626	21,814
Acquisitions and investments in oil and gas property/equipment	$266,043	$299,213

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

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

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Conventional shelf	$62,452	$88,473
Deepwater	40,615	49,001
Deep shelf	21,828	45,791
Onshore	66,583	94,134
Exploration and development capital expenditures	$191,478	$277,399

Our capital expenditures for the six months ended June 30, 2014 and 2013 were financed by cash flow from operating activities, borrowings on our revolving bank credit facility and cash on hand.

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

	Six Months Ended June 30,			
	2014		2013	
	Gross	Net	Gross	Net
Development wells:				
Offshore wells:				
Productive	—	—	2	2.0
Non-productive	—	—	—	—
Onshore wells:				
Productive	12	11.3	19	18.9
Non-productive	—	—	—	—
Total development wells	12	11.3	21	20.9
Exploration wells:				
Offshore wells:				
Productive	3	2.2	—	—
Non-productive	—	—	1	1.0
Onshore wells:				
Productive	9	8.9	4	3.9
Non-productive	1	1.0	—	—
Total exploration wells	13	12.1	5	4.9
Total wells	25	23.4	26	25.8

Exploration activities. During the six months ended June 30, 2014, three offshore exploration wells were completed. The Mississippi Canyon 243 (Matterhorn) A-5 side-track well was brought online during the first quarter and averaged over 800 Boe per day net since coming online. The Ship Shoal 349 (Mahogany) A-15 well was brought online during the second quarter and averaged over 900 Boe per day net since coming online. During the first quarter, the completion operations on the Mississippi Canyon 698 (Big Bend) well were finalized with first production expected in the second half of 2015 and is dependent on connection to a host platform. During the first six months of 2014, we completed nine exploration onshore wells, eight of which were vertical wells and one of which was a horizontal well.

Acquisitions and funding. We intend to continue to pursue acquisitions and joint venture opportunities during 2014 and beyond should we identify attractive opportunities. For example, in the second quarter, we completed the acquisition of the Woodside Properties and in the fourth quarter of 2013, we completed the acquisition of the Callon Properties as described in Part I, Item 1, Financial Statements – Note 2 – Acquisitions and Divestitures, of this Form 10-Q. We are actively evaluating opportunities and seek to complement our drilling and development projects with acquisitions providing acceptable rates of return.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. During the six months ended June 30, 2014, in East Texas at our Star Project, we reassigned approximately 160,000 gross acres back to our original assignor. During the six months ended June 30, 2014, we did not have any divestitures. During 2013, we sold our interests in various fields. See Part I, Item 1, Financial Statements – Note 2 – Acquisitions and Divestitures, of this Form 10-Q for additional information.

Capital Expenditure Budget for 2014. Our total capital expenditure budget for 2014 was increased by $185.0 million to $635.0 million. The increase will be devoted primarily to three additional deepwater wells, one shallow water well, three additional horizontal wells in the Permian Basin and acquisitions completed so far this year. The budget includes 50% for exploration, 37% for development and 13% for other items. Geographically, the budget is split 66% for offshore, 9% for completed offshore acquisitions and 25% for onshore. The budget does not include any potential acquisitions. We will continue to evaluate and bid on acquisition opportunities as they arise. We anticipate funding our 2014 capital budget, any potential acquisitions and other expenditures with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility, proceeds from divestitures, if any, and by accessing the capital markets to the extent necessary. Our 2014 capital budget is subject to change as conditions warrant.

Income taxes. During the six months ended June 30, 2014, we made no income tax payments and received $3.0 million in refunds. During the six months ended June 30, 2013, we made no income tax payments and received $4.9 million of refunds. For the remainder of 2014, we expect a substantial amount of our income tax will be deferred and expect payments, if any, to be primarily related to alternative minimum tax. We have $263.4 million of net operating loss carryforward (tax basis) available to offset future federal taxable income in 2014 and forward. We also have $12.1 million of alternative minimum tax credit carryforwards available to be utilized in 2014 and forward.

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

Contractual obligations. Updated information on certain contractual obligations is provided in Part I, Item 1, Financial Statements – Note 3 – Asset Retirement Obligations and Note 5 – Long-Term Debt, of this Form 10-Q. As of June 30, 2014, drilling rig commitments were approximately $13.4 million compared to $21.5 million as of December 31, 2013. The current drilling rig commitments expire within one year from June 30, 2014. Except for scheduled utilization, other contractual obligations as of June 30, 2014 did not change materially from the disclosures in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, of our Annual Report on Form 10-K for the year ended December 31, 2013.

Critical Accounting Policies

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

Recent Accounting Pronouncements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the six months ended June 30, 2014 did not change materially from the disclosures in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, of our Annual Report on Form 10-K for the year ended December 31, 2013. As such, the information contained herein should be read in conjunction with the related disclosures in our Annual Report on Form 10-K for the year ended December 31, 2013.

Commodity Price Risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. We currently have open crude oil derivative contracts to manage a portion of our exposure to commodity price risk from sales of oil for the balance of 2014. As of June 30, 2014, these derivative contracts had a notional quantity of 1.7 MMBbls. We do not designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of volatile oil prices, they may also limit future income from favorable price movements. See Part I, Item 1, Financial Statements – Note 4 – Derivative Financial Instruments, of this Form 10-Q for additional information.

Interest Rate Risk. As of June 30, 2014, we had $310.0 million outstanding on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the rates for the LIBOR and the margin, which ranges from 1.75% to 2.75% depending on the amount outstanding. We currently do not have any derivative instruments related to interest rates.

Item 4. Controls and Procedures

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

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

During the quarter ended June 30, 2014, there was no change in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements – Note 11 – Contingencies, of this Form 10-Q for information on various legal matters.

Item 1A. Risk Factors

Investors should carefully consider the risk factors included under Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2013, together with all of the other information included in this document, in our Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management. Notwithstanding the matters discussed herein, there have been no material changes in our risk factors as previously disclosed in Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2013.

Item 6. Exhibits

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

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on August 7, 2014.

W&T OFFSHORE, INC.
By: /s/ JOHN D. GIBBONS
John D. Gibbons
Senior Vice President and Chief Financial Officer

(Principal Financial Officer), duly authorized to sign on behalf of the registrant

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed February 24, 2006)
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
3.3	Certificate of Amendment to the Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q, filed July 31, 2012 (File No. 001-32414))
31.1*	Section 302 Certification of Chief Executive Officer.
31.2*	Section 302 Certification of Chief Financial Officer.
32.1**	Section 906 Certification of Chief Executive Officer and Chief Financial Officer.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Schema Document.
101.CAL**	XBRL Calculation Linkbase Document.
101.DEF**	XBRL Definition Linkbase Document.
101.LAB**	XBRL Label Linkbase Document.
101.PRE**	XBRL Presentation Linkbase Document.

* Filed herewith.
** Furnished herewith.