DUN & BRADSTREET CORP/NW
Form 4
March 22, 2010

FORM 4

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

OMB APPROVAL
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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
ADAMS AUSTIN A

(Last) (First) (Middle)

103 JFK PARKWAY

(Street)

SHORT HILLS, NJ 07078

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
DUN & BRADSTREET CORP/NW [DNB]

3. Date of Earliest Transaction (Month/Day/Year)
03/18/2010

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	03/18/2010		A		21.06 (1)	A	$ 73.36	6,436.66	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Phantom Stock Units - Deferred Compensation (2)	(3)	03/18/2010		A		9.107 (2)		(4)	(5)	Common Stock	9.107 (2)

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
ADAMS AUSTIN A 103 JFK PARKWAY SHORT HILLS, NJ 07078	X			

Signatures

/s/ Christine Cappuccia for Austin A. Adams	03/22/2010
**Signature of Reporting Person	Date

Explanation of Responses:

- * If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).
- ** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Acquired pursuant to a dividend reinvestment feature of the issuer's non-employee directors' stock incentive plan in connection with restricted stock units held by the reporting person.

(2) Phantom stock is reported in units vs. shares in the D&B Common Stock Fund of the issuer's non-employee directors' deferred compensation plan (the "Plan").

(3) Each phantom stock unit entitles the reporting person to a cash payment based on the value on the payout date of the issuer's common stock corresponding to such units. Based on the $73.35 closing price of the issuer's common stock on the transaction date, each unit corresponds to approximately 2.67 shares.

(4) The reporting person may transfer these phantom stock units to alternative investment funds in the Plan.

(5) These phantom stock units are payable in cash after the reporting person ceases to be a member of the issuer's board of directors.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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Current maturities of long-term debt

138,999

—

Long term debt, less current maturities

$

1,345,954

$

1,196,855

8.5% Senior Notes

At March 31, 2016 and December 31, 2015, our outstanding senior notes, which bear an annual interest rate of 8.50% and mature on June 15, 2019 (the "8.50% Senior Notes"), were classified as long-term at their carrying value. Interest on the 8.50% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the 8.50% Senior Notes is 8.4%, which includes amortization of debt issuance costs and premiums. 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 March 31, 2016.

11

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

9.00% Term Loan

At March 31, 2016 and December 31, 2015, our outstanding term loan, which bears an annual interest rate of 9.00% and matures on May 15, 2020 (the "9.00% Term Loan"), was classified as long-term at its carrying value. Interest on the 9.00% Term Loan is payable in arrears semi-annually on May 15 and November 15. The estimated annual effective interest rate on the 9.00% Term Loan is 9.7%, which includes amortization of debt issuance costs and discounts. The 9.00% Term Loan is secured by a second priority lien covering our oil and gas properties to the extent such properties secure first priority liens granted to secure indebtedness under our Credit Agreement. We are subject to various covenants under the terms governing the 9.00% Term Loan including, without limitation, covenants that limit our ability to incur other debt, pay dividends or distributions on our equity, merge or consolidate with other entities and make certain investments in other entities. We were in compliance with those covenants as of March 31, 2016.

Credit Agreement

The Credit Agreement provides a revolving bank credit facility. Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders, and the Company and the lenders may each request one additional determination per year. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. To the extent borrowings and letters of credit outstanding exceed the redetermined borrowing base, such excess or deficiency is required to be repaid within 90 days in three equal monthly payments. Letters of credit may be issued in amounts up to $150.0 million, provided availability under the revolving bank credit facility exists. The revolving bank credit facility is secured and is collateralized by our oil and natural gas properties. The Credit Agreement terminates on November 8, 2018.

The Credit Agreement contains various customary covenants for certain financial tests, as defined in the Credit Agreement and measured as of the end of each quarter, and for customary events of default. These financial test ratios and limits as of March 31, 2016 and thereafter are: (i) the First Lien leverage Ratio must be less than 1.50 to 1.00; (ii) the Current Ratio must be greater than 1.00 to 1.00; and (iii) the Secured Debt Leverage Ratio must be less than 3.50 to 1.00. As of March 31, 2016, our the First Lien Ratio was 1.48 to 1.00, the Current Ratio was 2.84 to 1.00 and the Secured Debt Leverage Ratio was 3.02 to 1.00. The customary events of default include: (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) bankruptcy or insolvency with respect to the Company or any of its subsidiaries guaranteeing borrowings under the revolving bank credit facility; or (iii) a change of control. The Credit Agreement contains cross-default clauses with the 8.50% Senior Notes and the 9.00% Term Loan, and these agreements contain similar cross-default clauses with the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of March 31, 2016.

In February 2016, we borrowed $340.0 million under the Credit Agreement. On March 23, 2016, the banks reduced our borrowing base to $150.0 million from $350.0 million in connection with the spring borrowing base redetermination. We are required to repay borrowings outstanding in excess of the redetermined borrowing base pursuant to the terms of the Credit Agreement. On March 31, 2016, we repaid $52.0 million leaving an outstanding balance under the Credit Agreement of $288.0 million as of March 31, 2016. On May 2, 2016, we repaid an additional $12.0 million. Additional payments are required of $64.0 million on May 31, 2016 and $64.0 million on June 30, 2016, in addition to interest payments on our long-term debt, which will bring total borrowings outstanding under the Credit Agreement in conformity with the borrowing base limitation. The Company has sufficient available cash to make these payments. The reduction in the borrowing base resulted in a proportional reduction in the unamortized costs related to the Credit Agreement of $1.4 million, which is included in the line Other (income) expense, net on the Condensed Statement of Operations.

As of March 31, 2016 and December 31, 2015, we had $1.0 million and $0.9 million, respectively, of letters of credit outstanding under the revolving bank credit facility. The estimated annual effective interest rate was 4.7% for the three months ended March 31, 2016 for average daily borrowings outstanding 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.

The foregoing description of the Credit Agreement does not purport to be complete and is qualified in its entirety by reference to the agreement.

12

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

For information about fair value measurements for our 8.50% Senior Notes, 9.00% Term Loan and revolving bank credit facility, refer to Note 6.

6. Fair Value Measurements

We measure the fair value of our open derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for the fair value measurement of our derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads, credit risk and published commodity futures prices. The fair values of our 8.50% Senior Notes and 9.00% Term Loan were based on quoted prices, although the market is not an active market; therefore, the fair value is classified within Level 2. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates.

The following table presents the fair value of our open derivatives and long-term debt, as reported in the Condensed Consolidated Balance Sheets (in thousands):

		March 31, 2016		December 31, 2015	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$6,060	$—	$7,672	$—
8.50% Senior Notes (1)	Level 2	—	108,000	—	324,000
9.00% Term Loan (1)	Level 2	—	144,000	—	217,500
Revolving bank credit facility (1)	Level 2	—	288,000	—	—

(1) The long-term debt items are reported on the Condensed Consolidated Balance Sheets at their carrying value as described in Note 5.

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

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our shareholders, and amendments to the Plan were approved by our shareholders in May 2013. As allowed by the Plan, during 2015 and in 2014, the Company granted restricted stock units ("RSUs") to certain of its employees. During the three months ended March 31, 2016, no RSUs were granted. RSUs are a long-term compensation component of the Plan, which are granted to only certain employees, and are subject to typical 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 typically based on the Company and the employee achieving certain pre-defined performance criteria.

During 2015, RSUs granted were subject to adjustments based on achievement of multiple 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 2015 and (ii) Adjusted EBITDA as a percent of total revenues ("Adjusted EBITDA Margin") for 2015. For 2015, the Company was below target for Adjusted

EBITDA and achieved the target for Adjusted EBITDA Margin.

During 2014, RSUs granted were subject to adjustments based on achievement of a combination of performance criteria, which was comprised of: (i) Adjusted EBITDA for 2014 and (ii) Adjusted EBITDA Margin for 2014. For 2014, the Company achieved the target for Adjusted EBITDA and was slightly below target for Adjusted EBITDA Margin.

13

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

All RSUs that are currently outstanding under the Plan are subject to employment-based criteria and vesting occurs in December of the second year after the grant. For example, the RSUs granted during 2014, adjusted for 2014 performance described above, will vest in December 2016 to eligible employees assuming employment-based criteria are also satisfied.

Under the Director Compensation Plan, shares of restricted stock (“Restricted Shares”) have been granted to the Company’s non-employee directors. Grants to non-employee directors were made during 2015, 2014 and 2013. The Restricted Shares are subject to service conditions and vesting occurs at the end of specified service periods unless approved by the Board.

At March 31, 2016, there were 4,239,548 shares of common stock available for issuance in satisfaction of awards under the Plan and 444,024 shares of common stock available for issuance in satisfaction of awards under the Director Compensation Plan. The shares available for both plans are reduced when Restricted Shares or shares of common stock are granted. RSUs reduce the shares available in the Plan when the RSUs are settled in shares of common stock, net of withholding tax. Although the Company has the option to settle RSUs in stock or cash at vesting, only common stock has been used to settle vested RSUs to date.

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

Awards Based on Restricted Stock to Non-Employee Directors. As of March 31, 2016, all of the unvested shares of Restricted Shares outstanding were issued to the non-employee directors. Restricted Shares 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.

For the outstanding Restricted Shares issued to the non-employee directors as of March 31, 2016, vesting is expected to occur as follows:

	Restricted Shares
2016	43,058
2017	20,092
2018	15,080
Total	78,230

There were no grants, forfeitures or vesting of Restricted Shares during the first quarter of 2016 or the first quarter of 2015.

Awards Based on Restricted Stock Units. As of March 31, 2016, the Company had outstanding RSUs issued to certain employees. As described above, the RSUs granted during 2015 and 2014 were 100% performance based and were subject to pre-defined performance measures and employment-based criteria. The fair values for the RSUs granted during 2015 and 2014 were determined using the Company’s closing price on the grant date.

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

14

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

A summary of activity in 2016 related to RSUs is as follows:

	Restricted Stock Units	
	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested, December 31, 2015	3,474,079	$ 7.42
Forfeited	(46,293)	6.71
Nonvested, March 31, 2016	3,427,786	7.43

For the outstanding RSUs issued to the eligible employees as of March 31, 2016, vesting is expected to occur as follows:

	Restricted Stock Units
2016	992,344
2017	2,435,442
Total	3,427,786

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 March 31,	
	2016	2015
Share-based compensation expense from:		
Restricted stock	$87	$93
Restricted stock units	2,449	2,817
Common shares	—	(94)
Total	$2,536	$2,816
Share-based compensation tax benefit:		
Tax benefit computed at the statutory rate	$888	$986

Unrecognized Share-Based Compensation. As of March 31, 2016, unrecognized share-based compensation expense related to our awards of Restricted Shares and RSUs was $0.4 million and $10.3 million, respectively. Unrecognized share-based compensation expense will be recognized through April 2018 for Restricted Shares and November 2017 for RSUs.

Cash-Based Incentive Compensation. As defined by the Plan, annual incentive awards may be granted to eligible employees and are typically payable in cash. These awards are performance-based awards consisting of one or more business or individual performance criteria and a targeted level or levels of performance with respect to each such criterion. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

During 2015, the Company issued cash-based incentive awards for 2015 that, in addition to being performance-based awards related to 2015 criteria, the payment of such awards is contingent on the Company achieving the following financial condition on or before December 31, 2017: Adjusted EBITDA less Interest Expense, as reported by the Company in its announced Earnings Release with respect to the end of any fiscal quarter plus three preceding quarters, exceeds $300.0 million. As the Company did not achieve this financial condition up through March 31, 2016, no amounts have been recognized to date related to the 2015 cash-based incentive awards. Amounts recorded during the three months ended March 31, 2015 relate to the 2014 cash-based awards, for which costs were recognized from the award date through February 2015 (the service period), and adjustments were recorded to true up previous estimates to actual payments.

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

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

	Three Months Ended March 31, 2016	2015
Share-based compensation included in:		
General and administrative expenses	$2,536	$2,816
Cash-based incentive compensation included in:		
Lease operating expense	—	361
General and administrative expenses [1]	—	(233)
Total charged to operating income	$2,536	$2,944

(1) Adjustments to true up estimates to actual payments resulted in net credit balances to expense for the three months ended March 31, 2015.

8. Income Taxes

Our income tax benefit for the three months ended March 31, 2016 and 2015 was $4.9 million and $103.6 million, respectively. Our annualized effective tax rate for the three months ended March 31, 2016 and 2015 was 2.5% and 28.9%, respectively. Both of these percentages differ from the federal statutory rate of 35.0% primarily due to recording and adjusting a valuation allowance for our deferred tax assets.

During the three months ended March 31, 2016 and 2015, we recorded a valuation allowance of $60.0 million and $22.5 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In addition, the realization depends on the ability to carryback certain items to prior years for refunds of taxes previously paid. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As of March 31, 2016 and December 31, 2015, we had a valuation allowance related to Federal, Louisiana and Alabama net operating losses and other deferred taxes. The tax years 2012 through 2015 remain open to examination by the tax jurisdictions to which we are subject.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense. During the three months ended March 31, 2016 and 2015, we recorded immaterial amounts of accrued interest expense related to our unrecognized tax benefit.

9. Earnings Per Share

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

	Three Months Ended March 31,	
	2016	2015
Net loss	$(190,509)	$(255,095)
Weighted average common shares outstanding	76,428	75,857
Basic and diluted loss per common share	$(2.49)	$(3.36)
Shares excluded due to being anti-dilutive (weighted-average)	3,528	1,993

16

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

10. Dividends

During the three months ended March 31, 2016 and the full year of 2015, we did not pay any dividends and a suspension of dividends remains in effect.

11. Contingencies

Supplemental Bonding Requirements by the BOEM. The significant reductions in crude oil and natural gas pricing since the middle of 2014 have adversely impacted our financial strength and have resulted in our inability to meet the relevant financial strength and reliability criteria set forth in the BOEM Notice To Lessee #2008-N07, Supplemental Bond Procedures, ("NTL #2008-N07"). Both W&T Offshore, Inc. and its subsidiary are now subject to supplemental bonding. In February and March 2016, we received several orders from the BOEM demanding that we provide additional supplemental bonding on certain Federal offshore oil and gas leases, rights of way and rights of use and easement owned and/or operated by the Company. One order was rescinded and re-issued and another one was rescinded. The outstanding orders total approximately $260.8 million. We have had discussions with the BOEM and its sister agency, the BSEE, since receiving the orders. See Note 12 for information on events occurring subsequent to March 31, 2016 for this item.

The issuers of such surety bonds may request, and in some cases, have requested, collateral, which could be significant and could impact our liquidity. In addition, pursuant to the terms of our agreements with various sureties under our existing bonds or under any additional bonds we may obtain, we are required to post collateral at any time, on demand, at the surety's discretion.

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 the ONRR's allegations contained in the notice. We intend to contest the fine to the fullest extent possible. A hearing on this matter is scheduled with an Administrative Law Judge on June 21, 2016 in Houston, Texas. 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 March 31, 2016 or December 31, 2015.

Apache Lawsuit. On December 15, 2014, Apache Corporation ("Apache") filed a lawsuit against W&T Offshore, Inc., alleging that W&T breached the joint operating agreement ("JOA") related to deepwater wells in the Mississippi Canyon area of the Gulf of Mexico. That lawsuit, styled Apache Corporation v. W&T Offshore, Inc., is currently pending in the United States District Court for the Southern District of Texas. Apache contends that W&T has failed to pay its proportional share of the costs associated with plugging and abandoning three wells that are subject to the JOA. We contend that the costs incurred by Apache are excessive and unreasonable. Apache seeks an award of unspecified actual damages, interest, court costs, and attorneys' fees. In February 2015, we made a payment to Apache for our net share of the amounts that we believe are reasonable to plug and abandon the three wells. Our estimate of the potential exposure ranges from zero to $32 million related to this matter, which excludes potential interest, court costs and attorneys' fees.

17

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

Insurance Claims. During the fourth quarter of 2012, underwriters of W&T's excess liability policies ("Excess Policies") (Indemnity Insurance Company of North America, New York Marine & General Insurance Company, Navigators Insurance Company, XL Specialty Insurance Company, National Liability & Fire Insurance Company ("Starr Marine") and Liberty Mutual Insurance Co.) filed declaratory judgment actions in the United States District Court for the Southern District of Texas (the "District Court") seeking a determination that our Excess Policies do not cover removal-of-wreck and debris claims arising from Hurricane Ike except to the extent we have first exhausted the limits of our Energy Package (defined as certain insurance policies relating to our oil and gas properties which includes named windstorm coverage) with only removal-of-wreck and debris claims. The court consolidated the various suits filed by the underwriters. In January 2013, we filed a motion for summary judgment seeking the court's determination that such Excess Policies do not require us to exhaust the limits of our Energy Package policies with only removal-of-wreck and debris claims. In July 2013, the District Court ruled in favor of the underwriters, adopting their position that the Excess Policies cover removal-of-wreck and debris claims only to the extent the limits of our Energy Package policies have been exhausted with removal-of-wreck and debris claims. We appealed the decision in the United States Court of Appeals for the Fifth Circuit (the "Fifth Circuit") and, in June 2014, the Fifth Circuit reversed the District Court's ruling and ruled in our favor. The underwriters filed three separate briefs requesting a rehearing or a certification to the Texas Supreme Court, all of which the Court denied. A brief was subsequently filed by one underwriter requesting a rehearing to the District Court of the Fifth Circuit's decision, which the District Court denied. Claims of approximately $43 million were filed, of which approximately $1 million was paid under the Energy Package and of which approximately $1 million was paid under our Comprehensive General Liability policy. One of the underwriters, Liberty Mutual Insurance Co., paid its portion of the settlement (approximately $5 million), in addition to a portion of interest owed. The other underwriters have not paid, and we filed a lawsuit in September 2014 against these underwriters for amounts owed, interest, attorney fees and damages. Subsequent to the filing of that lawsuit, Liberty Mutual Insurance Co. paid additional interest and Starr Marine has paid its portion ($5 million) of the first excess liability policy without interest. The lawsuit includes interest not paid by Starr Marine. The revised estimate of potential reimbursement is approximately $31 million, plus interest, attorney fees and damages, if any. Removal-of-wreck costs are recorded in Oil and natural gas properties and equipment on the Condensed Consolidated Balance Sheets and recoveries from claims made on these Excess Policies will be recorded as reductions in this line item, which will reduce our future depreciation, depletion, amortization and accretion ("DD&A") rate.

Royalties. In 2009, the Company recognized allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, the ONRR audited the calculations and support related to this usage fee, and in 2010, we were notified that the ONRR had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue in 2010 to reflect this disallowance; however, we disagree with the position taken by the ONRR. We filed an appeal with the ONRR, which was denied in May 2014. On June 17, 2014, we filed an appeal with the IBLA. W&T's brief was filed in November 2014 and we expect the briefing before the IBLA to be completed in 2016.

The ONRR has publicly announced an "unbundling" initiative to review the methodology employed by producers in determining the appropriate allowances for transportation and processing costs that are permitted to be deducted in determining royalties under Federal oil and gas leases. In the second quarter of 2015, pursuant to the initiative, the Company received requests from the ONRR for additional data regarding the Company's transportation and processing allowances on natural gas production that is processed through a specific processing plant. The Company also received a preliminary determination notice from the ONRR asserting its preliminary determination that the Company's allocation of certain processing costs and plant fuel use at another processing plant were impermissibly allowed as deductions in the determination of royalties owed under Federal oil and gas leases. The Company intends to submit a response to the preliminary determination asserting the reasonableness of its own allocation methodology of such costs. These open ONRR unbundling reviews, and any further similar reviews, could ultimately result in an order for payment of additional royalties under the Company's Federal oil and gas leases for current and prior periods. The Company is not able to determine the likelihood or range of any additional royalties or, if and when assessed, whether such amounts would be material.

18

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

Notices of Proposed Civil Penalty Assessment. The Company currently has three open Incidents of Noncompliance ("INCs") issued by the BSEE, which have not been settled as of the filing of this Form 10-Q. The INC's were issued during 2015 and relate to three separate offshore locations with occurrence dates ranging from July 2012 to June 2014. The proposed civil penalties for these INCs total $7.1 million. The Company has accrued approximately $1.0 million, which is the Company's best estimate of the final settlement once all appeals have been exhausted. The Company's position is that the proposed civil penalties are excessive given the specific facts and circumstances related to these INCs.

Iberville School Board Lawsuit. In August, 2013, a citation was issued on behalf of plaintiffs, the State of Louisiana and the Iberville Parish School Board, in their suit against the Company (among others) in the 18th Judicial District Court for the Parish of Iberville, State of Louisiana. This case involves claims by the Iberville Parish School Board that this property has allegedly been contaminated or otherwise damaged by certain defendants' oil and gas exploration and production activities. The plaintiff's claims include assessment costs, restoration costs, diminution of property value, punitive damages, and attorney fees and expenses, of which were not quantified in the claim. We cannot currently estimate our potential exposure, if any, related to this lawsuit. We are currently, and intend to continue, vigorously defending this litigation.

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. In addition, the BOEM considers all owners of record title and/or operating rights interest in an Outer Continental Shelf ("OCS") lease to be jointly and severally liable for the satisfaction of the supplemental bonding obligations and/or decommissioning obligations. Accordingly, we may be required to satisfy supplemental bonding obligations or decommissioning obligations of a defaulting owner of record title and/or operating rights interest in an OCS lease in which we are (or in some cases were) an owner of record title and/or operating rights interest in the same OCS lease. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business including matters related to alleged royalty underpayments on certain federal-owned properties. Although we can give no assurance about the outcome of pending legal and federal or state administrative proceedings and the effect such an outcome may have on us, we believe that any ultimate liability resulting from the outcome of such proceedings, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

Contingent Liability Recorded. There were no material expenses recognized related to accrued and settled claims, complaints and fines for the three months ended March 31, 2016 and 2015. As of March 31, 2016 and December 31, 2015, we had no material amounts recorded in liabilities for claims, complaints and fines.

12. Subsequent Events

Supplemental Bonding Requirements by the BOEM. Subsequent to March 31, 2016, we have filed appeals with the IBLA regarding three of the BOEM orders - specifically the February order that required W&T to post a total of $159.8 million in supplemental bonding and two March orders requiring $68.0 million in supplemental bonding. The objective of the Company remains to reach a mutual agreement on the financial assurance requirements of the demands. The issuance of any additional surety bonds to satisfy the BOEM orders or any future BOEM orders may require the posting of cash collateral, which may be significant, and the creation of escrow accounts. We continue to have discussions with the BOEM regarding these matters.

19

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

13. Supplemental Guarantor Information

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

(1) in connection with any sale or other disposition of all or substantially all of the assets of a Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary, if the sale or other disposition does not violate the Asset Sales provisions (as such terms are define in certain debt documents);

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

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

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

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

(6) at such time as such Guarantor Subsidiary is no longer required to be a Guarantor Subsidiary as described in certain debt documents, provided no event of default has occurred and is continuing.

The following condensed consolidating financial information presents the financial condition, results of operations and cash flows of the Parent Company and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company's results on a consolidated basis. Transfers of property were made from the Parent Company to the Guarantor Subsidiaries. As these transfers were transactions between entities under common control, the prior period financial information has been retrospectively adjusted for comparability purposes, as prescribed under authoritative guidance. None of the adjustments had any effect on the consolidated results for the current or prior periods presented.

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

Condensed Consolidating Balance Sheet as of March 31, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	$370,623	$—	$—	$370,623
Receivables:				
Oil and natural gas sales	197	27,706	—	27,903
Joint interest and other	116,184	—	(99,178)	17,006
Total receivables	116,381	27,706	(99,178)	44,909
Prepaid expenses and other assets	19,776	3,259	—	23,035
Total current assets	506,780	30,965	(99,178)	438,567
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,668,440	2,226,962	—	7,895,402
Furniture, fixtures and other	20,802	—	—	20,802
Total property and equipment	5,689,242	2,226,962	—	7,916,204
Less accumulated depreciation, depletion and amortization	5,276,838	1,908,552	(76,465)	7,108,925
Net property and equipment	412,404	318,410	76,465	807,279
Deferred income taxes	31,003	1,550	—	32,553
Restricted deposits for asset retirement obligations	16,171	—	—	16,171
Other assets	424,515	272,483	(692,773)	4,225
Total assets	$1,390,873	$623,408	$(715,486)	$1,298,795
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities:				
Accounts payable	$82,318	$9,727	$—	$92,045
Undistributed oil and natural gas proceeds	18,915	1,739	—	20,654
Asset retirement obligations	66,816	16,962	—	83,778
Accrued liabilities	39,486	99,178	(99,178)	39,486
Current portion of long-term debt	138,999	—	—	138,999
Total current liabilities	346,534	127,606	(99,178)	374,962
Long-term debt, less current maturities	1,345,954	—	—	1,345,954
Asset retirement obligations, less current portion	154,272	121,714	—	275,986
Other liabilities	335,043	—	(318,686)	16,357
Shareholders' equity (deficit):				
Common stock	1	—	—	1
Additional paid-in capital	426,035	704,885	(704,885)	426,035
Retained earnings (deficit)	(1,192,799)	(330,797)	407,263	(1,116,333)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity (deficit)	(790,930)	374,088	(297,622)	(714,464)
Total liabilities and shareholders' equity (deficit)	$1,390,873	$623,408	$(715,486)	$1,298,795

21

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

Condensed Consolidating Balance Sheet as of December 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Assets				
Current assets:				
Cash and cash equivalents	$ 85,414	$ —	$ —	$ 85,414
Receivables:				
Oil and natural gas sales	2,742	32,263	—	35,005
Joint interest and other	121,190	—	(99,178)	22,012
Total receivables	123,932	32,263	(99,178)	57,017
Prepaid expenses and other assets	25,375	1,504	—	26,879
Total current assets	234,721	33,767	(99,178)	169,310
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,682,793	2,219,701	—	7,902,494
Furniture, fixtures and other	20,802	—	—	20,802
Total property and equipment	5,703,595	2,219,701	—	7,923,296
Less accumulated depreciation, depletion and amortization	5,258,563	1,822,273	(147,589)	6,933,247
Net property and equipment	445,032	397,428	147,589	990,049
Deferred income taxes	27,251	344	—	27,595
Restricted deposits for asset retirement obligations	15,606	—	—	15,606
Other assets	498,782	266,748	(760,068)	5,462
Total assets	$ 1,221,392	$ 698,287	$ (711,657)	$ 1,208,022
Liabilities and Shareholders’ Equity				
Current liabilities:				
Accounts payable	$ 100,282	$ 9,515	$ —	$ 109,797
Undistributed oil and natural gas proceeds	20,463	976	—	21,439
Asset retirement obligations	63,716	20,619	—	84,335
Accrued liabilities	11,922	99,178	(99,178)	11,922
Total current liabilities	196,383	130,288	(99,178)	227,493
Long-term debt, less current maturities	1,196,855	—	—	1,196,855
Asset retirement obligations, less current portion	173,105	120,882	—	293,987
Other liabilities	329,129	—	(312,951)	16,178
Shareholders’ equity (deficit):				
Common stock	1	—	—	1
Additional paid-in capital	423,499	704,885	(704,885)	423,499
Retained earnings (deficit)	(1,073,413)	(257,768)	405,357	(925,824)
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders’ equity	(674,080)	447,117	(299,528)	(526,491)
Total liabilities and shareholders’ equity	$ 1,221,392	$ 698,287	$ (711,657)	$ 1,208,022

22

Explanation of Responses:

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

Condensed Consolidating Statement of Operations for the Three Months Ended March 31, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 30,512	$ 47,203	$ —	$ 77,715
Operating costs and expenses:				
Lease operating expenses	24,945	19,524	—	44,469
Production taxes	526	—	—	526
Gathering and transportation	1,553	3,539	—	5,092
Depreciation, depletion, amortization and accretion	20,623	38,161	4,949	63,733
Ceiling test write-down of oil and natural gas properties	—	50,384	66,175	116,559
General and administrative expenses	6,613	9,830	—	16,443
Derivative gain	(2,493)	—	—	(2,493)
Total costs and expenses	51,767	121,438	71,124	244,329
Operating loss	(21,255)	(74,235)	(71,124)	(166,614)
Loss of affiliates	(73,029)	—	73,029	—
Interest expense:				
Incurred	27,695	119	—	27,814
Capitalized	(224)	(119)	—	(343)
Other expense, net	1,306	—	—	1,306
Loss before income tax benefit	(123,061)	(74,235)	1,905	(195,391)
Income tax benefit	(3,676)	(1,206)	—	(4,882)
Net loss	$ (119,385)	$ (73,029)	$ 1,905	$ (190,509)

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

Condensed Consolidating Statement of Operations for the Three Months Ended March 31, 2015

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$ 82,463	$ 45,444	$ —	$ 127,907
Operating costs and expenses:				
Lease operating expenses	37,386	15,945	—	53,331
Production taxes	637	—	—	637
Gathering and transportation	2,548	2,276	—	4,824
Depreciation, depletion, amortization and accretion	75,152	50,315	—	125,467
Ceiling test write-down of oil and natural gas properties	190,695	69,695		260,390
General and administrative expenses	12,388	8,378	—	20,766
Total costs and expenses	318,806	146,609	—	465,415
Operating loss	(236,343)	(101,165)	—	(337,508)
Loss of affiliates	(65,627)	—	65,627	—
Interest expense:				
Incurred	22,232	714	—	22,946
Capitalized	(1,069)	(714)	—	(1,783)
Other expense, net	(2)	—	—	(2)
Loss before income tax benefit	(323,131)	(101,165)	65,627	(358,669)
Income tax benefit	(68,036)	(35,538)	—	(103,574)
Net loss	$ (255,095)	$ (65,627)	$ 65,627	$ (255,095)

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

Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2016

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net loss	$(119,385)	$ (73,029)	$ 1,905	$ (190,509)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	20,623	38,161	4,949	63,733
Ceiling test write-down of oil and natural gas properties	—	50,384	66,175	116,559
Debt issuance costs write-off/amortization of debt items	1,684	—	—	1,684
Share-based compensation	2,536	—	—	2,536
Derivative gain	(2,493)	—	—	(2,493)
Cash receipts on derivative settlements, net	4,105	—	—	4,105
Deferred income taxes	(3,676)	(1,206)	—	(4,882)
Loss of affiliates	73,029	—	(73,029)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	3,606	4,559	—	8,165
Joint interest and other receivables	4,979	—	—	4,979
Income taxes	(310)	—	—	(310)
Prepaid expenses and other assets	3,072	(7,492)	5,737	1,317
Asset retirement obligation settlements	(584)	(2,596)	—	(3,180)
Accounts payable, accrued liabilities and other	14,773	18,969	(5,737)	28,005
Net cash provided by operating activities	1,959	27,750	—	29,709
Investing activities:				
Investment in oil and natural gas properties and equipment	(3,147)	(9,756)	—	(12,903)
Changes in operating assets and liabilities associated with investing activities	(2,686)	(17,994)	—	(20,680)
Proceeds from sales of assets	1,000	—	—	1,000
Net cash used in investing activities	(4,833)	(27,750)	—	(32,583)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	340,000	—	—	340,000
Repayments of long-term debt – revolving bank credit facility	(52,000)	—	—	(52,000)
Other	83	—	—	83
Net cash provided by financing activities	288,083	—	—	288,083
Increase in cash and cash equivalents	285,209	—	—	285,209
Cash and cash equivalents, beginning of period	85,414	—	—	85,414
Cash and cash equivalents, end of period	$370,623	$ —	$ —	$ 370,623

25

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

Condensed Consolidating Statement of Cash Flows for the Three Months Ended March 31, 2015

	Parent Company (In thousands)	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
Operating activities:				
Net loss	$(255,095)	$ (65,627)	$ 65,627	$ (255,095)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, amortization and accretion	75,152	50,315	—	125,467
Ceiling test write-down of oil and natural gas properties	190,695	69,695	—	260,390
Amortization of debt issuance costs and premium	156	—	—	156
Share-based compensation	2,816	—	—	2,816
Deferred income taxes	(83,649)	(19,925)	—	(103,574)
Earnings of affiliates	65,627	—	(65,627)	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	14,636	6,485	—	21,121
Joint interest and other receivables	14,533	—	—	14,533
Income taxes	15,287	(15,612)	—	(325)
Prepaid expenses and other assets	(21,690)	68,599	(29,663)	17,246
Asset retirement obligations	(19,122)	(432)	—	(19,554)
Accounts payable, accrued liabilities and other	(40,260)	334	29,663	(10,263)
Net cash provided by (used in) operating activities	(40,914)	93,832	—	52,918
Investing activities:				
Investment in oil and natural gas properties and equipment	(18,750)	(64,015)	—	(82,765)
Changes in operating assets and liabilities associated with investing activities	(22,562)	(29,614)	—	(52,176)
Investment in subsidiary	203	—	(203)	—
Purchases of furniture, fixtures and other	(226)	—	—	(226)
Net cash used in investing activities	(41,335)	(93,629)	(203)	(135,167)
Financing activities:				
Borrowings of long-term debt – revolving bank credit facility	82,000	—	—	82,000
Repayments of long-term debt – revolving bank credit facility	(15,000)	—	—	(15,000)
Other	(50)	—	—	(50)
Investment from parent	—	(203)	203	—
Net cash provided by (used in) financing activities	66,950	(203)	203	66,950
Decrease in cash and cash equivalents	(15,299)	—	—	(15,299)
Cash and cash equivalents, beginning of period	23,666	—	—	23,666
Cash and cash equivalents, end of period	$8,367	$ —	$ —	$ 8,367

26

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, 2015 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. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 54 offshore fields in federal and state waters (50 producing and four fields capable of producing). We currently have under lease approximately 850,000 gross acres, with approximately 500,000 gross acres on the shelf and approximately 350,000 gross acres in the deepwater. A majority of our daily production is derived from wells we operate. 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.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for the first quarter of 2016 were comprised of 48.3% oil and condensate, 9.1% NGLs and 42.6% natural gas, determined using the energy equivalency ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the price per one barrel oil equivalent ("Boe") for oil, NGLs and natural gas has differed significantly from time to time. In the first quarter of 2016, revenues from the sale of oil and NGLs made up 72.0% of our total revenues compared to 69.6% for the first quarter of 2015. For the first quarter of 2016, our combined total production was 10.3% lower than the first quarter of 2015 due to lower NGLs and natural gas production. For the first quarter of 2016, our total revenues were 39.2% lower than the first quarter of 2015 due primarily to significantly lower realized prices for oil, NGLs and natural gas. See Results of Operations – Three months ended March 31, 2016 Compared to the Three Months ended March 31, 2015 in this Item for additional information on our revenues and production.

On October 15, 2015, we sold our interests in the Yellow Rose onshore field in the Permian Basin to Ajax. Our interest in the field covered approximately 25,800 net acres. During the first quarter of 2015, the Yellow Rose field accounted for approximately 7% of our production and revenues. In connection with the sale, we retained a non-expense bearing ORRI in production from the working interests sold, which percentage varies on a sliding scale from one percent for each month that the NYMEX prompt month contract trading price for light sweet crude oil is at or below $70.00 per barrel to a maximum of four percent for each month that such NYMEX trading price is greater than $90.00 per barrel. Internal estimates of proved reserves at the date of the sale were 19.0 MMBoe, consisting of approximately 71% oil, 11% NGL and 18% natural gas. Including adjustments from an effective date of January 1, 2015, the adjusted sales price was $370.8 million of cash and the buyer assumed the ARO associated with our interests in the Yellow Rose field, which we had estimated at $6.9 million at the time of the sale, and the buyer assumed other liabilities of $1.1 million. We used a portion of the proceeds of the sale to repay all the outstanding borrowings under our revolving bank credit facility, while the remaining balance of approximately $98 million was added to available cash.

Our operating results are strongly influenced by the price of the commodities that we produce and sell. The price of those commodities is affected by both domestic and international factors, including domestic production. Beginning in the second half of 2014 and continuing through the first quarter of 2016, crude oil prices have fallen dramatically from a peak of over $100 per barrel for WTI in June 2014. In addition, prices of NGLs and natural gas have fallen significantly from 2014 levels. The current market imbalance is predominantly supply driven caused by a number of issues that are described below:

The U.S. Energy Information Administration (“EIA”) estimates the worldwide crude oil and petroleum liquids supply will exceed demand in 2016, resulting in crude oil and other petroleum liquids inventories increasing by 1.4 million barrels per day. The estimate of inventory build for 2016 has been increased from the previous estimate of 0.7 million barrels per day. In addition, the inventory build for 2015 was revised upwards from 1.9 million barrels per day to 2.1 million barrels per day. EIA estimates inventory builds in each quarter of 2016 and the first half of 2017, and forecasts the first inventory withdraw occurring in the third quarter of 2017. Comparing the first quarter of 2016 to the first quarter of 2015, worldwide supply increased by 0.9 million barrels per day, primarily due to increases from OPEC, while U.S. and Canada supply was basically flat between the two quarters. EIA’s estimate for 2016 has supply increasing over 2015 by 0.5 million barrels per day, with Iran accounting for most of the increase and partially offset by decreases in the U.S. and the North Sea. EIA’s forecast for supply from OPEC does not assume any production cuts from collaborative agreements. EIA’s estimate has consumption increasing in 2016 over 2015 by 1.2 million barrels per day, with the increases coming primarily from China and other Asian countries. Downside risk was noted for China as their economic growth may be less than expected.

While many U.S. producers reduced capital in 2015 compared to 2014 and have further reduced capital budgets for 2016, the impact of reduced drilling did not reduce overall oil and other liquids production in the U.S. for the first quarter of 2016, as production was basically flat from the first quarter of 2015. Per EIA’s estimates, U.S. oil production will decrease in the second quarter of 2016 compared to the first quarter of 2016 and will continue to decrease throughout the remainder of 2016. U.S. oil production for the balance of 2016 is estimated to be lower than the respective prior year quarters by 0.5 to 1.0 million barrels per day.

During the first quarter of 2016, our average realized oil sales price was $26.73, down from $43.04 per barrel (37.9% lower) for the first quarter of 2015. The two primary benchmarks reported upon are the prices for WTI and Brent crude oil. As reported by the EIA, WTI crude oil prices averaged $33.35 per barrel for the first quarter of 2016, down from $48.49 per barrel (31.2% lower) for the first quarter of 2015. Brent crude average oil prices decreased to $33.84 per barrel for the first quarter of 2016, down from $53.98 per barrel (37.3% lower) for the first quarter of 2015. Our average realized oil sales price or the first quarter of 2016 differs from the benchmark crude prices due to premiums or discounts (referred to as differentials), volume weighting and other factors. All of our oil for the first quarter of 2016 was produced offshore in the Gulf of Mexico and is characterized as Light Louisiana Sweet ("LLS"), Heavy Louisiana Sweet ("HLS"), Poseidon and others. WTI is frequently used to value domestically produced crude oil, and the majority of our oil production is priced using the spot price for WTI as a base price, then adjusted for the type and quality of crude oil and other factors. Just like crude oil prices, the differentials for our offshore crude oil have also experienced volatility. For example, the monthly average differentials of WTI versus LLS, HLS and Poseidon for the first quarter of 2016 were a positive $1.60 and $0.80, and a negative $3.71 per barrel, respectively, compared to positive $2.60 and $1.42, and a negative $2.14 per barrel, respectively, for the first quarter of 2015. The majority of our crude oil is priced similar to Poseidon and, therefore, is experiencing negative differentials. In addition, a few of our crude oil fields have a negative quality bank adjustment and production from two of our crude oil fields is being transported via barge, which is more expensive than pipeline transportation.

EIA projects average crude oil prices for WTI and Brent to decrease for the year 2016 over 2015 by approximately $14.00 per barrel and $18.00 per barrel, respectively, and to increase in 2017 by approximately $6.00 per barrel for each. One factor identified by EIA that could cause crude oil prices to deviate significantly from their projections is capacity of global oil storage (which is unknown) to absorb the continuing inventory builds. If the cost of storage increases due to using marginal storage options such as oil tankers, crude oil prices could experience downward pressure. Other factors noted that may have a significant impact on future crude oil prices include the pace of economic growth and unplanned supply disruptions. In addition, the strength in the U.S. dollar relative to other currencies also has an impact on crude pricing. Because all barrels are traded in U.S. dollars, as the U.S. dollar gains strength, crude prices are lower in U.S. dollars but are more expensive in other currencies.

During the first quarter of 2016, our average realized NGLs sales price decreased 17.0% compared to the first quarter of 2015. Two major components of our NGLs, ethane and propane, typically make up over 70% of an average NGL barrel. During the first quarter of 2016, average prices for domestic ethane decreased 14% and average domestic propane prices decreased 28% from the first quarter of 2015. Average price decreases for other domestic NGLs were 22% to 30%. The price changes were reflective of the price changes for crude oil and natural gas. Per EIA, production of ethane and propane increased in the first quarter of 2016 over the first quarter of 2015 by 14% and 7%, respectively. Ethane and propane inventory levels for the first quarter of 2016 were higher than the comparable quarter in 2015. The number of heating degree days for the winter of 2016 were lower than the prior year, which contributed to the higher propane inventory levels. As long as U.S. crude oil and natural gas production remain high and the price ratio of crude oil to natural gas remains wide (as measured on a six to one energy equivalency), the production of NGLs may continue to be high relative to historical norms, which would in turn suggest continued weak prices, or possibly further price reductions, especially for the prices of ethane and propane. Many natural gas processing facilities have been and will likely continue re-injecting ethane back into the natural gas stream after processing due to insufficient ethane demand, which negatively impacts production and natural gas prices. Once propane is extracted from the natural gas stream, it is not re-injected and is sold as a separate component. As propane inventories build with no offsetting increase in demand, propane prices are expected to continue to be weak or weaken further.

During the first quarter of 2016, our average realized natural gas sales price decreased 33.2% compared to the first quarter of 2015. According to the EIA, spot prices for natural gas at Henry Hub (the primary U.S. price benchmark) were 31.4% lower in the first quarter of 2016 from the first quarter of 2015. Natural gas prices are more affected by domestic issues (as compared to crude oil prices), such as weather (particularly extreme heat or cold), supply, local demand issues, other fuel competition (coal) and domestic economic conditions, and they have historically been subject to substantial fluctuation. However, with the surplus of natural gas that has plagued the industry since 2012, natural gas prices have been weak and the fluctuations in prices have been limited to the lower end of the price range. Heating degree days for the first quarter of 2016 were 18% lower than the first quarter of 2015, which has a direct impact on demand for natural gas. The U.S. natural gas inventories at the end of March 2016 were slightly above the previous end-of-March record high set in 2012 and were 67% higher than the same period last year. U.S. consumption decreased in the first quarter of 2016 compared to the first quarter of 2015 by 6%, which was basically the same percentage decrease for production. Consumption decreases came from lower residential and commercial usage and partially offset by higher electric power usage.

The average price of natural gas continues to be weak from an overall economic standpoint, and we expect continued weakness in natural gas prices for a number of reasons, including (i) producers may continue to drill in order to secure and to hold large lease positions before expiration, particularly in shale and similar resource plays, (ii) natural gas continuing to be produced as a by-product of oil drilling, (iii) production efficiency gains being achieved in the shale gas areas resulting from better hydraulic fracturing, horizontal drilling, pad drilling and production techniques and (iv) re-injecting ethane into the natural gas stream as indicated above, which increases the natural gas supply.

EIA projects natural gas prices to decrease for the year 2016 to $2.25 per Mcf compared to $2.71 per Mcf in 2015. U.S. production is projected to be higher in 2016 compared to 2015 by 1% despite the decrease in drilling activity. Natural gas usage for power generation is expected to remain in the 33%-34% range for 2016 and 2017, which is approximately equivalent to 2015 due to lower natural gas prices compared to coal and new Federal regulations related to coal usage.

During the first quarter of 2016, the number of rigs drilling for oil and natural gas in the U.S. is significantly below 2014 levels due to lower crude oil and natural gas prices. According to Baker Hughes, the oil rig count at December 2014, December 2015 and March 2016 was 1,482, 536 and 362, respectively. The number of rigs drilling for oil as of March 2016 was a seven-year low. The U.S. natural gas rig count at December 2014, December 2015 and March 2016 was 328, 162 and 88, respectively. The U.S. natural gas rig count as of March 2016 was a 29-year low (the extent of data provided by Baker Hughes). In the Gulf of Mexico, there were 54 rigs (42 oil and 12 natural gas) at the end of 2014; 25 rigs (20 oil and five natural gas) as of the end of 2015; and 24 rigs (19 oil and five natural gas) as of March 2016. The majority of working rigs in the Gulf of Mexico are currently “floaters” with very few jack-up rigs working.

As required by the full cost accounting rules, we perform our ceiling test calculation each quarter using the SEC pricing guidelines, which require using the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price adjusted for price differentials. The average price using the SEC required methodology at March 31, 2016 was $42.77 per barrel for WTI crude oil and $2.40 per MMBtu for Henry Hub natural gas before adjustments. Due to the decrease in the 12-month average price for both crude oil and natural gas, we recorded ceiling test write-downs of the carrying value of our oil and natural gas properties in the first quarter of 2016 of $116.6 million. For the first quarter and full year of 2015, the ceiling test write-downs were $260.4 million and $987.2 million, respectively. Incurrence of further write downs is dependent primarily on the price of crude oil and natural gas, but also is affected by quantities of proved reserves, future development costs and future lease operating costs.

At this time, we expect to incur a further ceiling test impairment write-down in the second quarter of 2016 assuming commodities prices do not increase dramatically. While it is difficult to project future impairment write-downs in light of numerous variables involved, the following price sensitivity calculation using basic assumptions is provided to illustrate the impact of lower commodities pricing on impairment charges and proved reserves volumes. Assuming pro-forma 12-month average prices were determined by using the April 1, 2016 and May 1, 2016 benchmark commodities prices of $33.25 and $42.50 per barrel for WTI crude oil and $1.93 and $1.91 per MMBtu for Henry Hub natural gas, respectively, (before adjustments). Then also assume May 1, 2016 prices are used as a proxy for June 1, 2016 prices and removing the second quarter 2015 prices from the 12-month average, we calculated that the benchmark 12-month average prices would decrease to $39.38 per barrel for WTI crude oil and $2.22 per MMBtu for Henry Hub natural gas (before adjustments). If such pro-forma pricing was used in our ceiling test calculation as of March 31, 2016, and assuming no other changes, our ceiling test impairment write-down for the first quarter of 2016 would have increased by $106.2 million to $222.8 million

Using pro forma 12-month average commodity prices computed as described in the previous paragraph, our proved reserves would have decreased by approximately 3.1 MMBoe. This is as a result of removing 27% of our proved undeveloped reserves due to the lack of economic viability at such prices, and reductions at some fields due to shortened time horizons. The foregoing calculation was made without regard to additions or other further revisions to proved reserves estimated at March 31, 2016 other than as a result of such pricing changes.

30

In February 2016, we borrowed $340 million under the Credit Agreement. On March 23, 2016, the banks reduced our borrowing base to $150 million from $350 million in connection with the spring borrowing base redetermination. We are required to repay borrowings outstanding in excess of the redetermined borrowing base pursuant to the terms of the Credit Agreement. On March 31, 2016, we repaid $52 million leaving an outstanding balance under the Credit Agreement of $288 million as of March 31, 2016. In addition, we had approximately $1 million of letters of credit outstanding as of March 31, 2016. On May 2, 2016, we repaid an additional $12 million. Additional payments are required of $64 million on May 30, 2016 and $64 million on June 30, 2016, in addition to interest payments on our long-term debt, which will bring total borrowings outstanding under the Credit Agreement in conformity with the borrowing base limitation. See Financial Statements – Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q for additional information.

The significant reductions in crude oil and natural gas pricing commencing in the second half 2014 have adversely impacted the Company's financial strength and have resulted in the Company's inability to meet the relevant financial strength and reliability criteria set forth in the NTL #2008-N07. Prior to 2015, we were partially exempt from providing such financial assurances under our corporate structure. Currently, substantially all of our operations are subject to supplemental bonding. In February and March 2016, we received several orders from the BOEM demanding that we provide additional supplemental bonding on certain Federal offshore oil and gas leases, rights of way and rights of use and easement owned and/or operated by the Company. One order was rescinded and re-issued and another one was rescinded. The outstanding orders total approximately $261 million. We have filed appeals with the IBLA regarding three of the BOEM orders - specifically the February order that required W&T to post a total of approximately $160 million in supplemental bonding and two March orders requiring approximately $68 million in supplemental bonding. We have had discussions with the BOEM and its sister agency, the BSEE, since receiving the orders. The objective of the Company remains to reach a mutual agreement on the financial assurance requirements. The issuance of any additional surety bonds to satisfy the BOEM orders or any future BOEM orders may require the posting of cash collateral, which may be significant, and the creation of escrow accounts. We continue to have discussions with the BOEM regarding these matters. See our Annual Report on Form 10-K for the year ended December 31, 2015, Item 1A, Risk Factors, for additional information.

Due to the continued deterioration of commodity prices and the outlook for the remainder of 2016, we have set our 2016 capital expenditure budget at $15 million. This is a significant reduction from our 2015 and 2014 incurred capital expenditures of $231 million and $630 million, respectively. We have the flexibility to make this reduction to our 2016 capital expenditure budget because we have no long term rig commitments and no pressure from partners to drill or complete a well. Moreover, we expect our deepwater projects completed in 2015, combined with new production from our Ewing Bank 910 A-8 well, will help with 2016 production levels. However, unplanned downtime, pipeline maintenance, and well performance are factors leading to lower estimated production in 2016 from 2015. We do not expect to lose drilling opportunities at this spending level and have no significant lease expiration issues in 2016. In addition, our plans include spending $76 million in 2016 for ARO, which is an increase from $33 million spent on ARO in 2015.

On the cost side, we have seen relatively significant reductions in our lease operating expenses as a result of our cost reduction programs combined with reduced rates from vendors for supplies, equipment and contract labor. These cost reduction programs and reduced supplier rates have also lowered capital expenditures, ARO settlements and ARO estimates.

Our short-term focus is on conserving capital and maintaining liquidity. In light of our limited access to capital and liquidity, we are not pursuing any significant acquisitions at this time. We continue to closely monitor current and forecasted prices to assess if changes are needed to our plans. See our Annual Report on Form 10-K for the year ended December 31, 2015, Item 1A, Risk Factors, for additional information.

31

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 March 31, 2016	2015	Change	%
	(In thousands, except percentages and per share data)			
Financial:				
Revenues:				
Oil	$50,936	$81,527	$(30,591)	(37.5)%
NGLs	4,995	7,446	(2,451)	(32.9)%
Natural gas	20,270	37,175	(16,905)	(45.5)%
Other	1,514	1,759	(245)	(13.9)%
Total revenues	77,715	127,907	(50,192)	(39.2)%
Operating costs and expenses:				
Lease operating expenses	44,469	53,331	(8,862)	(16.6)%
Production taxes	526	637	(111)	(17.4)%
Gathering and transportation	5,092	4,824	268	5.6 %
Depreciation, depletion, amortization and accretion	63,733	125,467	(61,734)	(49.2)%
Ceiling test write-down of oil and natural gas properties	116,559	260,390	(143,831)	(55.2)%
General and administrative expenses	16,443	20,766	(4,323)	(20.8)%
Derivative gain	(2,493)	—	(2,493)	NM
Total costs and expenses	244,329	465,415	(221,086)	(47.5)%
Operating loss	(166,614)	(337,508)	170,894	(50.6)%
Interest expense, net of amounts capitalized	27,471	21,163	6,308	29.8 %
Other (income) expense, net	1,306	(2)	1,308	NM
Loss before income tax benefit	(195,391)	(358,669)	163,278	(45.5)%
Income tax benefit	(4,882)	(103,574)	98,692	(95.3)%
Net loss	$(190,509)	$(255,095)	$64,586	(25.3)%
Basic and diluted loss per common share	$(2.49)	$(3.36)	$0.87	(25.9)%

NM – not meaningful

32

	Three Months Ended March 31, 2016	2015	Change	% [2]
Operating: [1]				
Net sales:				
Oil (MBbls)	1,906	1,894	12	0.6 %
NGLs (MBbls)	358	443	(85)	(19.2)%
Natural gas (MMcf)	10,071	12,349	(2,278)	(18.4)%
Total oil equivalent (MBoe)	3,942	4,395	(453)	(10.3)%
Total natural gas equivalents (MMcfe)	23,651	26,372	(2,721)	(10.3)%
Average daily equivalent sales (Boe/day)	43,317	48,837	(5,520)	(11.3)%
Average daily equivalent sales (Mcfe/day)	259,903	293,022	(33,119)	(11.3)%
Average realized sales prices:				
Oil ($/Bbl)	$26.73	$43.04	$(16.31)	(37.9)%
NGLs ($/Bbl)	13.96	16.81	(2.85)	(17.0)%
Natural gas ($/Mcf)	2.01	3.01	(1.00)	(33.2)%
Oil equivalent ($/Boe)	19.33	28.70	(9.37)	(32.6)%
Natural gas equivalent ($/Mcfe)	3.22	4.78	(1.56)	(32.6)%
Average per Boe ($/Boe):				
Lease operating expenses	$11.28	$12.13	$(0.85)	(7.0)%
Gathering and transportation	1.29	1.10	0.19	17.3 %
Production costs	12.57	13.23	(0.66)	(5.0)%
Production taxes	0.13	0.14	(0.01)	(7.1)%
DD&A	16.17	28.55	(12.38)	(43.4)%
General and administrative expenses	4.17	4.72	(0.55)	(11.7)%
	$33.04	$46.64	$(13.60)	(29.2)%
Average per Mcfe ($/Mcfe):				
Lease operating expenses	$1.88	$2.02	$(0.14)	(6.9)%
Gathering and transportation	0.22	0.19	0.03	15.8 %
Production costs	2.10	2.21	(0.11)	(5.0)%
Production taxes	0.02	0.02	—	—
DD&A	2.69	4.76	(2.07)	(43.5)%
General and administrative expenses	0.70	0.79	(0.09)	(11.4)%
	$5.51	$7.78	$(2.27)	(29.2)%

(1) 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.

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

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

33

	Three Months Ended March 31,			
	2016	2015	Change	%
Offshore - Wells drilled (gross):	1	2	(1)	(50.0)%
Offshore - Productive wells drilled (gross)	1	2	(1)	(50.0)%

The Company drilled onshore wells during 2015, which were included with the sale of the Yellow Rose field in October 2015 and were excluded in the table above as the Company has sold, relinquished or let expire essentially all onshore leasehold interest.

Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015

Revenues. Total revenues decreased $50.2 million, or 39.2%, to $77.7 million for the first quarter of 2016 as compared to the first quarter of 2015. Oil revenues decreased $30.6 million, or 37.5%, NGLs revenues decreased $2.5 million, or 32.9%, natural gas revenues decreased $16.9 million, or 45.5% and other revenues decreased $0.2 million. The decrease in oil revenues was attributable to a 37.9% decrease in the average realized sales price to $26.73 per barrel for the first quarter of 2016 from $43.04 per barrel for the first quarter of 2015, with sales volumes up slightly. The decrease in NGLs revenues was attributable to a 17.0% decrease in the average realized sales price to $13.96 per barrel for the first quarter of 2016 from $16.81 per barrel for the first quarter of 2015 and a decrease of 19.2% in sales volumes. The decrease in natural gas revenues resulted from a 33.2% decrease in the average realized natural gas sales price to $2.01 per Mcf for the first quarter of 2016 from $3.01 per Mcf for the first quarter of 2015 and from a decrease of 18.4% in sales volumes. Overall, production declined 10.3% on a BOE basis. We experienced increases in production at the Mississippi Canyon 698 field (Big Bend) and the Mississippi Canyon 782 field (Dantzler), which began production in the fourth quarter of 2015. Also, production increases were achieved at the Mississippi Canyon 582 field (Medusa), the Main Pass 108 field and the Brazos A-133 field. Offsetting were production declines primarily from the sale of the Yellow Rose field; decreases at Ship Shoal 349 (Mahogany) due primarily to pipeline and operational issues; natural production declines at Mississippi Canyon 243 (Matterhorn), Garden Banks 302 (Power Play), Mississippi Canyon 506 (Wrigley), Viosca Knoll 783 (Tahoe) and Garden Banks 293 (Pyrenees) and other fields; and production deferrals affecting various fields. Production deferrals, which occurred at multiple locations, were attributable to third-party pipeline outages, operational issues, and maintenance. We estimate production deferrals were 0.8 million barrels of oil equivalent (“MMBoe”) during the first quarter of 2016 compared to 0.5 million MMBoe for the first quarter of 2015.

Revenues from oil and liquids as a percent of our total revenues were 72.0% for the first quarter of 2016 compared to 69.6% for the first quarter of 2015. Our average realized NGLs sales price as a percent of our average realized oil sales price increased to 52.2% for the first quarter of 2016 compared to 39.1% for the first quarter of 2015.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, and facilities maintenance, decreased $8.9 million, or 16.6%, to $44.5 million in the first quarter 2016 compared to the first quarter of 2015. On a per Boe basis, lease operating expenses decreased to $11.28 per Boe during the first quarter of 2016 compared to $12.13 per Boe during the first quarter of 2015. On a component basis, base lease operating expenses decreased $5.2 million, workover expense decreased $1.9 million and insurance premiums decreased $1.6 million. Base lease operating expenses decreased primarily due to lower costs from service providers and the sale of the Yellow Rose field; partially offset by lower production handling fees (cost offsets) at our Matterhorn field and increases in expenses related to our new deepwater fields at Dantzler and Big Bend. The decrease in workover costs was primarily due to the sale of the Yellow Rose field.

Production taxes. Production taxes decreased $0.1 million to $0.5 million for the first quarter of 2016 compared to the first quarter of 2015. Most of our production is from federal waters where no production taxes are imposed. Our Fairway field, which is in state waters, is subject to production taxes.

Depreciation, depletion, amortization and accretion. DD&A, which includes accretion for ARO, decreased to $16.17 per Boe for the first quarter of 2016 from $28.55 per Boe for the first quarter of 2015. On a nominal basis, DD&A decreased to $63.7 million, or 49.2%, for the first quarter of 2016 from $125.5 million for the first quarter of 2015. DD&A on a per Boe and nominal basis decreased primarily due to the ceiling test write-downs recorded during 2015 (the first quarter 2016 ceiling test write-down will not affect the DD&A rate until the second quarter of 2016) and lower capital expenditures in relation to DD&A expense, which lowers the full-cost pool subject to DD&A. In addition, the proceeds from the sale of our Yellow Rose field reduced the full cost pool along with the removal of future development costs associated with the Yellow Rose field reserves. Other factors affecting the DD&A rate are lower future development costs on remaining reserves and lower proved reserves volumes.

Ceiling test write-down of oil and natural gas properties. For the first quarter of 2016, we recorded a non-cash ceiling test write-down of $116.6 million as the book value of our oil and natural gas properties exceeded the ceiling test limitation. The write-down is the result of decreases in prices for all three commodities we sell, which are crude oil, NGLs and natural gas. For the first quarter of 2015, the ceiling test write-down was $260.4 million. See Financial Statements and Supplementary Data – Note 1 - Basis of Presentation under Part I, Item 1 of this Form 10-Q, which provides a description of the ceiling test limit determination, and above under the section Overview in this Item regarding our prospects for a future significant ceiling test write-down and a price sensitivity computation.

General and administrative expenses ("G&A"). G&A decreased to $16.4 million, or 20.8%, for the first quarter of 2016 from $20.8 million for the first quarter of 2015 primarily due to decreases in headcount related expense (salaries, benefits, and contractor expenses) and costs related to surety bonds (due to timing), partially offset by higher legal and professional services costs and higher medical claims. G&A on a per BOE basis was $4.17 per Boe for the first quarter of 2016 compared to $4.72 per Boe for the first quarter of 2015.

Derivative gain. For the first quarter of 2016, there was a $2.5 million net derivative gain recorded for derivative contracts for crude oil and natural gas. We entered into derivative contracts for crude oil and natural gas during the second quarter of 2015, relating to 2015 and 2016 estimated production. For the first quarter of 2015, there were no derivative contracts.

Interest expense. Interest expense incurred was $27.8 million in the first quarter of 2016, up from $22.9 million in the first quarter of 2015. The increase was primarily attributable to increased borrowings on the revolving bank credit facility and the issuance of the 9.00% Term Loan in May 2015 with an aggregate principal of $300.0 million. The aggregate principal amount of our 8.50% Senior Notes outstanding was $900.0 million in both periods. During the first quarter of 2016 and 2015, $0.3 million and $1.8 million, respectively, of interest costs were capitalized related to unevaluated oil and natural gas properties. The decrease is primarily attributable to the sale of the Yellow Rose field in the fourth quarter of 2015 and reclassifying certain unevaluated properties to the full cost pool during the first quarter of 2016 and the full year of 2015.

Other (income) expense, net. Effective in March 2016, the borrowing base on the revolving bank credit facility was redetermined and reduced to $150.0 million from $350.0 million. The reductions in the borrowing base resulted in a proportional reduction of $1.4 million in the unamortized debt issuance costs related to the revolving bank credit facility.

Income tax benefit. Our income tax benefit for the first quarter of 2016 and 2015 was $4.9 million and $103.6 million, respectively, with the change attributable primarily to changes in the pre-tax loss and changes in the valuation allowance recorded for the respective periods. Our annualized effective tax rate for the first quarter of 2016 and 2015 was 2.5% and 28.9%, respectively, and differs from the federal statutory rate of 35% primarily due to recording and adjusting a valuation allowance related to federal and state deferred tax assets. During the three months ended March 31, 2016 and 2015, we recorded valuation allowances of $60.0 million and $22.5 million, respectively, related to federal and state deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

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, make related interest payments and satisfy our asset retirement obligations. 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.

Due to the decline of commodity prices that commenced in the second half of 2014, we expect our future revenues, earnings, liquidity and ability to invest in future reserve growth to continue to be negatively impacted. Other potential negative impacts of such price weakness include:

- our ability to meet our financial covenants in future periods;
- recognizing additional ceiling test write-downs of the carrying value of our oil and gas properties;
- reductions in our proved reserves and the estimated value thereof;
- additional supplemental bonding and potential collateral requirements;
- reductions in our borrowing base under the Credit Agreement;
- our ability to fund capital expenditures needed to replace produced reserves, which must be replaced on a long-term basis to provide cash to fund liquidity needs described above.

As a result of the potential for these events, we have engaged legal and financial advisors to assist the Board of Directors and our management team to evaluate the various alternatives available to us, which may include, among other things, securities offerings and other financing activities, joint ventures and sales of properties. We may also from time to time seek to retire or purchase our outstanding debt through open market or privately negotiated cash purchases or exchange our existing debt for equity securities or debt securities or term loans, which may be secured by a lien on our assets. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. However, no assurances can be given that any of these alternatives will be available in 2016 or in future years.

In addition, these events could impact our ability to comply with the covenants under our Credit Agreement or other debt instruments, which would force us to engage the lenders or bondholders in discussions regarding further amendments or covenant relief. We may have to reduce future cash outlays for capital expenditures and other activities until such time as operating margins improve sufficiently and market conditions recover or stabilize. Realization of any of these events would depend on the longevity and severity of such price weakness.

In February 2016, we borrowed $340 million under the Credit Agreement. On March 23, 2016, the banks reduced our borrowing base to $150 million from $350 million in connection with the spring borrowing base redetermination. We are required to repay borrowings outstanding in excess of the redetermined borrowing base pursuant to the terms of the Credit Agreement. On March 31, 2016, we repaid $52 million leaving an outstanding balance under the Credit Agreement of $288 million as of March 31, 2016. In addition, we had approximately $1 million of letters of credit outstanding as of March 31, 2016. On May 2, 2016, we repaid an additional $12 million. Additional payments are required of $64 million on May 30, 2016 and $64 million on June 30, 2016, in addition to interest payments on our long-term debt, which will bring total borrowings outstanding under the Credit Agreement in conformity with the borrowing base limitation. See Financial Statements – Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q for additional information.

In February and March 2016, we received several orders from the BOEM demanding that we provide additional supplemental bonding on certain Federal offshore oil and gas leases, rights of way and rights of use and easement owned and/or operated by the Company. One order was rescinded and re-issued and another one was rescinded. The outstanding orders total approximately $261 million. We have filed appeals with the IBLA regarding three of the BOEM orders - specifically the February order that required W&T to post a total of approximately $160 million in supplemental bonding and two March orders requiring approximately $68 million in supplemental bonding. We have had discussions with the BOEM and its sister agency, the BSEE, since receiving the orders. The objective of the Company remains to reach a mutual agreement on the financial assurance requirements. The issuance of any additional surety bonds to satisfy the BOEM orders or any future BOEM orders may require the posting of cash collateral, which may be significant, and the creation of escrow accounts. We continue to have discussions with the BOEM regarding these matters. See our Annual Report on Form 10-K for the year ended December 31, 2015, Item 1A, Risk Factors, for additional information.

Cash Flow and Working Capital. Net cash provided by operating activities for the first quarter of 2016 and 2015 was $29.7 million and $52.9 million, respectively. Cash flows from operating activities, before changes in working capital and ARO settlements, were a negative $9.3 million in the first quarter of 2016, a decrease of $39.5 million compared to the $30.2 million generated during the first quarter of 2015. The change in cash flows excluding working capital and ARO settlements was primarily due to lower realized prices for all our commodities - oil, NGLs and natural gas and lower production volumes, partially offset by lower operating expenses. Our combined average realized sales price per Boe decreased 32.6%, which lowered revenues $42.1 million. Combined volumes on a Boe basis decreased 10.3%, which lowered revenues by $7.8 million.

The changes in working capital and ARO settlements increased operating cash flows by $39.0 million and $22.8 million in the first quarter of 2016 and 2015, respectively, resulting in a difference of $16.2 million. The 9.00% Term Loan was issued in May 2015, which increased accrued interest between the two periods. In addition, settlements of ARO liabilities were lower in the first quarter of 2016 compared to the first quarter of 2015.

Net cash used in investing activities during the first quarter of 2016 and 2015 was $32.6 million and $135.2 million, respectively, which represents our investments in oil and gas properties and equipment. There were no acquisitions of significance during the first quarter of 2016 and 2015. Investments in oil and natural gas properties on an accrual basis in the first quarter of 2016 were $12.9 million compared to $82.8 million in the first quarter of 2015. The majority of expenditures during the first quarter of 2016 related to investments in the deepwater. In addition, adjustments from working capital changes associated with investing activities used net cash of $20.7 million in the first quarter of 2016 compared to net cash usage of $52.2 million in the first quarter of 2015.

Net cash provided by financing activities for the first quarter of 2016 and 2015 was $288.1 million and $67.0 million, respectively. The net cash provided for the first quarter of 2016 and 2015 was attributable to borrowings on the revolving bank credit facility.

Credit Agreement and Long-Term Debt. At March 31, 2016, $288.0 million was outstanding under our revolving bank credit facility. At December 31, 2015, we did not have any borrowings outstanding on the revolving bank credit facility. During the first quarter of 2016, the outstanding borrowings on the revolving bank credit facility ranged from zero to $340.0 million. At March 31, 2016 and December 31, 2015, $900.0 million in aggregate principal amount of our 8.50% Senior Notes and $300.0 million in aggregate principal amount of our 9.00% Term Loan were outstanding.

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 spring redetermination occurred in March 2016, which is discussed above. The lenders and the Company have the option for an additional redetermination every year. The Credit

Agreement contains financial covenants calculated as of the last day of each fiscal quarter, which include thresholds on financial ratios, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement, the 8.50% Senior Notes and the 9.00% Term Loan as of March 31, 2016. See Financial Statements - Note 5 – Long-Term Debt under Part I, Item 1 of this Form 10-Q for additional information.

Derivative Financial Instruments. From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of March 31, 2016, we had outstanding open derivatives for crude oil and natural gas. These derivatives provide downside protection against a portion of our remaining 2016 production and will provide cash inflows when crude oil or natural gas prices average below $40.00 per barrel and $2.25 per MMBtu, respectively, in a month. See Financial Statements - Note 4 - Derivative Financial Instruments under Part I, Item 1 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 $161.2 million has been collected through December 31, 2015. In June 2014, the Fifth Circuit reversed a lower court's ruling in holding that our Excess Policies cover removal-of-wreck and debris claims arising from Hurricane Ike, even though we exhausted the limits of our Energy Package with non-removal-of-wreck and debris claim. Several of the underwriters have not paid us amounts we claim are due under such Excess Policies in accordance with the Fifth Circuit ruling. We filed a lawsuit in September 2014 against certain underwriters for amounts owed, interest, attorney fees and damages. We subsequently received reimbursement from certain underwriters of the Excess Policies of approximately $10 million. We believe we are still owed additional reimbursement of removal-of-wreck costs of approximately $31 million, plus interest, attorney fees and damages, if any. Given the Fifth Circuit's ruling, we expect to be reimbursed and compensated for all these costs, interest, fees and damages. See Financial Statements - Note 11 - Contingencies under Part I, Item 1 of this Form 10-Q 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, 2016. A per-occurrence retention amount of $30.0 million for named windstorm events must be satisfied by us before our insurers will indemnify us for losses and we co-insure 15% of our named windstorm coverage. The risk exposure varies per property and we have exposure for applicable retentions, co-insurance amounts and coverage limits. 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.

Our general and excess liability policies are effective until May 1, 2017 and provide for $300.0 million of coverage for bodily injury and property damage liability, including coverage for liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility requirement under the Oil Pollution Act of 1990, we are required to evidence $150.0 million of financial responsibility to the BSEE.

Although we were able to renew our general and excess liability policies, and Energy Package in May 2016 and June of 2015, respectively, our insurers may not continue to offer this type and level of coverage to us in the future, or our costs may increase substantially as a result of increased premiums and there could be an increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have claims, the insurers will not pay our claims. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

38

Explanation of Responses:

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, available liquidity and the results of our exploration and development activities. The following table presents our capital expenditures on an accrual basis for exploration, development and other leasehold costs and acquisitions:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Exploration (1)	$1,505	$28,336
Development (1)	9,468	48,735
Seismic, capitalized interest, and other	1,930	5,694
Acquisitions and investments in oil and gas property/equipment	$12,903	$82,765

(1) Reported geographically in the subsequent table.

The following table presents our exploration and development capital expenditures on an accrual basis geographically:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Conventional shelf	$1,741	$7,992
Deepwater	9,339	60,604
Deep shelf	(107)	2
Onshore	—	8,473
Exploration and development capital expenditures	$10,973	$77,071

Our capital expenditures for the first quarter of 2016 were financed by cash flow from operating activities, sales of properties, borrowings on our revolving bank credit facility and cash on hand.

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

		Three Months Ended March 31,			
		2016		2015	
		Gross	Net	Gross	Net
Development wells -	Productive	—	—	—	—
Exploration wells -	Productive	1	0.5	2	0.4
Total wells		1	0.5	2	0.4

The Company drilled onshore wells during 2015, which were included with the sale of the Yellow Rose field in October 2015 and were excluded in the table above as the Company has sold, relinquished or let expire essentially all onshore leasehold interest.

Exploration Activities. During the first quarter of 2016, the Ewing Bank 954 A-8 exploration well, which is part of the Ewing Bank 910 field, was completed and began producing on March 1, 2016. Subsequent to March 31, 2016, we had no wells being drilled. In 2015, we had one offshore well where drilling was deferred and the rig continues to be stacked on location.

Divestitures. Periodically, we sell properties as part of the management of our property portfolio. As previously discussed, in 2015 we sold our interest in the Yellow Rose field for $370.8 million cash after adjustments, reduced related ARO for $6.9 million and transferred the obligation of other related liabilities of $1.1 million. See Financial Statements - Note 2 – Divestitures under Part I, Item 1 of this Form 10-Q for additional information.

39

Capital Expenditure Budget for 2016. Because of the continued deterioration of commodity prices and the outlook for the remainder of 2016, our capital expenditure budget for 2016 is $15 million. In light of our limited access to capital and liquidity, we are not pursuing any significant acquisitions at this time. See the Overview section in this Item for additional information.

Income Taxes. During the first quarter of 2016 and 2015, we did not make any income tax payments nor receive any refunds of significance. For the remainder of 2016, we expect that a substantial portion of our income tax will be deferred and payments, if any, will be primarily related to state taxes. We have $418.4 million of Federal net operating loss carryforwards (tax basis) available to offset future federal taxable income in 2016 and forward. We also have $12.1 million of alternative minimum tax credit carryforwards (tax basis) available to be utilized in 2016 and forward.

Dividends. During the first quarter of 2016 and the full year of 2015, we did not pay any dividends and a suspension of dividends remains in effect.

Asset Retirement Obligations. Each quarter, we review and revise our ARO estimates. Our ARO at March 31, 2016 and December 31, 2015 were $359.8 million and $378.3 million, respectively. Our estimate of ARO spending for the April 2016 to March 2017 time period is $83.8 million. As each of these estimates are for work to be performed in the future, and in the case of our non-current ARO, are for many years in the future, actual expenditures could be substantially different than our estimates. See our Annual Report on Form 10-K for the year ended December 31, 2015, Item 1A, Risk Factors, for additional information.

Contractual Obligations. Updated information on certain contractual obligations is provided in Financial Statements – Note 3 – Asset Retirement Obligations, Note 5 – Long-Term and Note 12 – Subsequent Events under Part I, Item 1 of this Form 10-Q. As of March 31, 2016, drilling rig commitments were approximately $4.8 million compared to $7.0 million as of December 31, 2015. The current drilling rig commitments expire within one year from March 31, 2016. Except for scheduled utilization, other contractual obligations as of March 31, 2016 did not change materially from the disclosures in Management's Discussion and Analysis of Financial Condition and Results of Operations, of our Annual Report under Part II, Item 7 on Form 10-K for the year ended December 31, 2015.

Critical Accounting Policies

Our significant accounting policies are summarized in Financial Statements and Supplementary Data under Part II, Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2015. Also refer to Financial Statements - Note 1 - Basis of Presentation under Part 1, Item 1 of this Form 10-Q.

Recent Accounting Pronouncements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information about market risks for the first quarter of 2016 did not change materially from the disclosures in Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2015. 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, 2015.

Commodity Price Risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs and natural gas price declines have adversely affected our revenues, net cash provided by operating activities and profitability and could have further impact on our business in the future. As of March 31, 2016, we had open derivative contracts related to a portion of estimated production for the remainder of 2016. We historically have not designated our commodity derivatives as hedging instruments and any future derivative commodity contracts are not expected to be designated as hedging instruments. Use of these contracts may reduce the effects of volatile oil prices, but they also may limit future income from favorable price movements. See Financial Statements - Note 4 - Derivative Financial Instruments under Part I, Item 1 of this Form 10-Q for additional information.

Interest Rate Risk. As of March 31, 2016, we had $288.0 million outstanding on our revolving bank credit facility. The revolving bank credit facility has a variable interest rate, which is primarily impacted by the rates for the LIBOR and the margin, which ranges from 2.25% to 3.25% depending on the amount outstanding. As of March 31, 2016, we did not have any derivative instruments related to interest rates.

Item 4. Controls and Procedures

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

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our CEO and CFO have each concluded that as of March 31, 2016, 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 March 31, 2016, 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, 2015, together with all of the other information included in this document, in our Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.

The potential effects of the recent decrease in crude oil prices are discussed under Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2015 and also discussed in the Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations in the Overview section of this Form 10-Q.

Notwithstanding the matters discussed herein, there have been no material changes in our risk factors as previously disclosed in Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2015.

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 May 5, 2016.

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 25, 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 or Furnished herewith.

44