PATTERSON UTI ENERGY INC
Form 10-Q
October 28, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

R QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015

or

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

Commission file number 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

DELAWARE	75-2504748
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
450 GEARS ROAD, SUITE 500	
HOUSTON, TEXAS	77067
(Address of principal executive offices)	(Zip Code)

(281) 765-7100

(Registrant's telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes R No ¨

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes £ No R

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

147,178,930 shares of common stock, $0.01 par value, as of October 22, 2015

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

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PART I — FINANCIAL INFORMATION

ITEM 1. Financial Statements

The following unaudited condensed consolidated financial statements include all adjustments which are, in the opinion of management, necessary for a fair statement of the results for the interim periods presented.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited, in thousands, except share data)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$76,465	$43,012
Accounts receivable, net of allowance for doubtful accounts of $3,537 and $3,546 at September 30, 2015 and December 31, 2014, respectively	301,710	663,404
Federal and state income taxes receivable	30,952	81,726
Inventory	17,422	32,251
Deferred tax assets, net	37,809	37,075
Other	41,383	51,624
Total current assets	505,741	909,092
Property and equipment, net	4,023,199	4,131,071
Goodwill and intangible assets	93,520	220,813
Deposits on equipment purchases	35,863	112,379
Other	19,843	20,656
Total assets	$4,678,166	$5,394,011
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$165,547	$382,438
Accrued expenses	180,530	173,466
Current portion of long-term debt	50,000	12,500
Total current liabilities	396,077	568,404
Borrowings under revolving credit facility	—	303,000
Other long-term debt	815,000	670,000
Deferred tax liabilities, net	826,163	935,660
Other	9,829	11,137
Total liabilities	2,047,069	2,488,201
Commitments and contingencies (see Note 9)		
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—

Common stock, par value $.01; authorized 300,000,000 shares with 190,387,622 and 189,262,876 issued and 147,180,382 and 146,444,291 outstanding at September 30, 2015 and December 31, 2014, respectively	1,904	1,893
Additional paid-in capital	1,006,306	984,674
Retained earnings	2,531,923	2,811,815
Accumulated other comprehensive income	(1,991)	6,463
Treasury stock, at cost, 43,207,240 shares and 42,818,585 shares at September 30, 2015 and December 31, 2014, respectively	(907,045)	(899,035)
Total stockholders' equity	2,631,097	2,905,810
Total liabilities and stockholders' equity	$4,678,166	$5,394,011

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited, in thousands, except per share data)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenues:				
Contract drilling	$261,817	$482,212	$951,616	$1,346,698
Pressure pumping	154,407	348,692	580,752	895,530
Oil and natural gas	6,027	14,724	20,343	38,844
Total operating revenues	422,251	845,628	1,552,711	2,281,072
Operating costs and expenses:				
Contract drilling	136,718	278,195	503,376	784,572
Pressure pumping	138,597	281,016	494,078	722,801
Oil and natural gas	2,519	3,275	8,096	9,421
Depreciation, depletion, amortization and impairment	332,151	237,825	689,457	538,573
Impairment of goodwill	124,561	—	124,561	—
Selling, general and administrative	18,582	18,896	70,595	58,117
Net gain on asset disposals	(1,362)	(3,870)	(7,276)	(8,705)
Total operating costs and expenses	751,766	815,337	1,882,887	2,104,779
Operating income (loss)	(329,515)	30,291	(330,176)	176,293
Other income (expense):				
Interest income	323	234	924	618
Interest expense, net of amount capitalized	(9,254)	(6,993)	(27,044)	(21,430)
Other	16	—	16	3
Total other expense	(8,915)	(6,759)	(26,104)	(20,809)
Income (loss) before income taxes	(338,430)	23,532	(356,280)	155,484
Income tax expense (benefit):				
Current	(42,446)	48,618	(10,221)	101,233
Deferred	(70,006)	(41,062)	(110,231)	(50,830)
Total income tax expense (benefit)	(112,452)	7,556	(120,452)	50,403
Net income (loss)	$(225,978)	$15,976	$(235,828)	$105,081
Net income (loss) per common share:				
Basic	$(1.54)	$0.11	$(1.61)	$0.72
Diluted	$(1.54)	$0.11	$(1.61)	$0.71
Weighted average number of common shares outstanding:				
Basic	145,662	144,798	145,317	143,778
Diluted	145,662	146,991	145,317	146,101
Cash dividends per common share	$0.10	$0.10	$0.30	$0.30

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited, in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(225,978)	$15,976	$(235,828)	$105,081
Other comprehensive loss, net of taxes of $0 for all periods:				
Foreign currency translation adjustment	(2,909)	(4,899)	(8,454)	(3,766)
Total comprehensive income (loss)	$(228,887)	$11,077	$(244,282)	$101,315

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

(unaudited, in thousands)

	Common Stock Number of Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
Balance, December 31, 2014	189,263	$ 1,893	$984,674	$2,811,815	$ 6,463	$(899,035)	2,905,810
Net loss				(235,828)	—	—	(235,828)
Foreign currency translation adjustment	—	—	—	—	(8,454)	—	(8,454)
Issuance of restricted stock	1,176	12	(12)	—	—	—	—
Vesting of stock unit awards	15	—	—	—	—	—	—
Forfeitures of restricted stock	(66)	(1)	—	—	—	—	(1)
Stock-based compensation	—	—	21,186	—	—	—	21,186
Tax benefit related to stock-based compensation	—	—	458	—	—	—	458
Payment of cash dividends	—	—	—	(44,064)	—	—	(44,064)
Purchase of treasury stock	—	—	—	—	—	(8,010)	(8,010)
Balance, September 30, 2015	190,388	$ 1,904	$ 1,006,306	$2,531,923	$ (1,991)	$(907,045)	$2,631,097

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited, in thousands)

	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities:		
Net income (loss)	$(235,828)	$105,081
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and impairment	689,457	538,573
Impairment of goodwill	124,561	—
Dry holes and abandonments	159	337
Deferred income tax benefit	(110,231)	(50,830)
Stock-based compensation expense	21,186	19,945
Net gain on asset disposals	(7,276)	(8,705)
Changes in operating assets and liabilities:		
Accounts receivable	359,304	(143,039)
Income taxes receivable/payable	52,037	13,701
Inventory and other assets	27,579	(6,419)
Accounts payable	(120,740)	71,865
Accrued expenses	7,274	22,414
Other liabilities	(1,443)	3,410
Net cash provided by operating activities	806,039	566,333
Cash flows from investing activities:		
Purchases of property and equipment and acquisitions	(608,220)	(773,791)
Proceeds from disposal of assets	15,920	22,499
Net cash used in investing activities	(592,300)	(751,292)
Cash flows from financing activities:		
Purchases of treasury stock	(8,010)	(13,554)
Dividends paid	(44,064)	(43,652)
Tax benefit related to stock-based compensation	458	8,682
Debt issuance costs	(1,979)	—
Proceeds from long-term debt	200,000	—
Repayment of long-term debt	(17,500)	(7,500)
Proceeds from borrowings under revolving credit facility	54,000	—
Repayment of borrowings under revolving credit facility	(357,000)	—
Proceeds from exercise of stock options	—	30,726
Net cash used in financing activities	(174,095)	(25,298)
Effect of foreign exchange rate changes on cash	(6,191)	(658)
Net increase (decrease) in cash and cash equivalents	33,453	(210,915)
Cash and cash equivalents at beginning of period	43,012	249,509
Cash and cash equivalents at end of period	$76,465	$38,594
Supplemental disclosure of cash flow information:		
Net cash (paid) received during the period for:		
Interest, net of capitalized interest of $4,946 in 2015 and $5,268 in 2014	$(18,734)	$(13,678)
Income taxes	$63,785	$(74,252)

Non-cash investing and financing activities:		
Net (decrease) increase in payables for purchase of property and equipment	$(95,371)	$125,271
Net decrease (increase) in deposits on equipment purchases	$76,516	$(59,728)

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Consolidation and Presentation

The unaudited interim condensed consolidated financial statements include the accounts of Patterson-UTI Energy, Inc. (the "Company") and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Except for wholly-owned subsidiaries, the Company has no controlling financial interests in any entity which would require consolidation.

The unaudited interim condensed consolidated financial statements have been prepared by management of the Company pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted pursuant to such rules and regulations, although the Company believes the disclosures included either on the face of the financial statements or herein are sufficient to make the information presented not misleading. In the opinion of management, all adjustments which are of a normal recurring nature considered necessary for a fair statement of the information in conformity with accounting principles generally accepted in the United States of America have been included. The Unaudited Condensed Consolidated Balance Sheet as of December 31, 2014, as presented herein, was derived from the audited consolidated balance sheet of the Company, but does not include all disclosures required by accounting principles generally accepted in the United States of America. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2014. The results of operations for the nine months ended September 30, 2015 are not necessarily indicative of the results to be expected for the full year.

The U.S. dollar is the functional currency for all of the Company's operations except for its Canadian operations, which uses the Canadian dollar as its functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders' equity.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value.

The Company provides a dual presentation of its net income (loss) per common share in its unaudited condensed consolidated statements of operations: Basic net income (loss) per common share ("Basic EPS") and diluted net income (loss) per common share ("Diluted EPS").

Basic EPS excludes dilution and is computed by first allocating earnings between common stockholders and holders of non-vested shares of restricted stock. Basic EPS is then determined by dividing the earnings attributable to common stockholders by the weighted average number of common shares outstanding during the period, excluding non-vested shares of restricted stock.

Diluted EPS is based on the weighted average number of common shares outstanding plus the dilutive effect of potential common shares, including stock options, non-vested shares of restricted stock and restricted stock units. The dilutive effect of stock options and restricted stock units is determined using the treasury stock method. The dilutive effect of non-vested shares of restricted stock is based on the more dilutive of the treasury stock method or the two-class method, assuming a reallocation of undistributed earnings to common stockholders after considering the dilutive effect of potential common shares other than non-vested shares of restricted stock.

The following table presents information necessary to calculate net income (loss) per share for the three and nine month periods ended September 30, 2015 and 2014 as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding because their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
BASIC EPS:				
Net income (loss)	$(225,978)	$15,976	$(235,828)	$105,081
Adjust for (income) loss attributed to holders of non-vested restricted stock	2,359	(160)	2,436	(1,074)
Income (loss) attributed to common stockholders	$(223,619)	$15,816	$(233,392)	$104,007
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	145,662	144,798	145,317	143,778
Basic net income (loss) per common share	$(1.54)	$0.11	$(1.61)	$0.72
DILUTED EPS:				
Income (loss) attributed to common stockholders	$(223,619)	$15,816	$(233,392)	$104,007
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	145,662	144,798	145,317	143,778
Add dilutive effect of potential common shares	—	2,193	—	2,323
Weighted average number of diluted common shares outstanding	145,662	146,991	145,317	146,101
Diluted net income (loss) per common share	$(1.54)	$0.11	$(1.61)	$0.71
Potentially dilutive securities excluded as anti-dilutive	7,840	442	7,840	473

2. Stock-based Compensation

The Company uses share-based payments to compensate employees and non-employee directors. The Company recognizes the cost of share-based payments under the fair-value-based method. Share-based awards consist of equity instruments in the form of stock options, restricted stock or restricted stock units and have included service and, in certain cases, performance conditions. The Company's share-based awards also include share-settled performance unit awards. Share-settled performance unit awards are accounted for as equity awards. The Company issues shares of common stock when vested stock options are exercised, when restricted stock is granted and when restricted stock units and share-settled performance unit awards vest.

Stock Options — The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model. Volatility assumptions are based on the historic volatility of the Company's common stock over the most recent period equal to the expected term of the options as of the date the options are granted. The expected term assumptions are based on the Company's experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options are granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. Weighted-average assumptions used to estimate the grant date fair values for stock options granted for the three and nine month periods ended September 30, 2015 and 2014 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Volatility	NA	35.64%	37.95%	35.89%
Expected term (in years)	NA	5.00	5.00	5.00
Dividend yield	NA	1.18%	2.00%	1.17%
Risk-free interest rate	NA	1.62%	1.37%	1.76%

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Stock option activity from January 1, 2015 to September 30, 2015 follows:

	Underlying Shares	Weighted Average Exercise Price
Outstanding at January 1, 2015	6,086,250	$ 22.32
Granted	831,000	$ 20.06
Exercised	—	—
Cancelled	(10,000)	$ 16.59
Expired	(600,000)	$ 26.06
Outstanding at September 30, 2015	6,307,250	$ 21.68
Exercisable at September 30, 2015	5,134,697	$ 21.39

Restricted Stock — For all restricted stock awards to date, shares of common stock were issued when the awards were made. Non-vested shares are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable dividends are paid on non-vested shares of restricted stock. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity from January 1, 2015 to September 30, 2015 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock outstanding at January 1, 2015	1,493,059	$ 26.93
Granted	792,100	$ 20.60
Vested	(728,400)	$ 24.74
Forfeited	(65,853)	$ 26.22
Non-vested restricted stock outstanding September 30, 2015	1,490,906	$ 24.67

Restricted Stock Units — For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units are subject to forfeiture for failure to fulfill service conditions. Non-forfeitable cash dividend equivalents are paid on certain non-vested restricted stock units. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock unit activity from January 1, 2015 to September 30, 2015 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock units outstanding at January 1, 2015	34,085	$ 30.20

Granted	22,100	$ 20.85
Vested	(14,499)	$ 27.37
Forfeited	—	—
Non-vested restricted stock units outstanding September 30, 2015	41,686	$ 26.22

Performance Unit Awards — In 2011, 2012, 2013, 2014 and 2015, the Company granted stock-settled performance unit awards to certain executive officers (the "Stock-Settled Performance Units"). The Stock-Settled Performance Units provide for the recipients to receive a grant of shares of stock upon the achievement of certain performance goals established by the Compensation Committee during the performance period. The performance units will only have a payout if total shareholder return is positive for the performance period and, when compared to the peer group, is at or above the 25th percentile. The performance period for the Stock-Settled Performance Units is the three year period commencing on April 1 of the year of grant. For the 2012 and 2013 Stock-Settled Performance Units, the performance period can extend for an additional two years in certain circumstances. The performance goals for the Stock-Settled Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee. These goals are considered to be market conditions under the relevant accounting standards and the market conditions were factored into the determination of the fair value of the performance units. Generally, the recipients will receive a target number of shares if the Company's total shareholder return is positive and, when compared to the peer group, is at the 50^{th} percentile and two times the target if at the 75^{th} percentile or higher. If the Company's total shareholder return is positive, and, when compared to the peer group, is at the 25^{th} percentile, the recipients will only receive one-half of the target number of shares. The grant of shares when achievement is between the 25^{th} and 75^{th} percentile will be determined on a pro-rata basis. The target number of shares with respect to the 2012 Stock-Settled Performance Units was 192,000. The performance period for the 2012 Stock-Settled Performance Units ended on March 31, 2015, and the Company's total shareholder return was at the 87^{th} percentile. In April 2015, 384,000 shares were issued to settle the 2012 Stock-Settled Performance Units.

The total target number of shares with respect to the Stock-Settled Performance Units is set forth below:

	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards
Target number of shares	190,600	154,000	236,500	192,000	144,375

Because the performance units are stock-settled awards, they are accounted for as equity awards and measured at fair value on the date of grant using a Monte Carlo simulation model. The fair value of the Stock-Settled Performance Units is set forth below (in thousands):

	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards
Fair value at date of grant	$ 4,052	$ 5,388	$ 5,564	$ 3,065	$ 5,569

These fair value amounts are charged to expense on a straight-line basis over the performance period. Compensation expense associated with the Stock-Settled Performance Units is shown below (in thousands):

	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards

Three months ended September 30, 2014	NA	$ 449	$ 464	$ 255	NA
Three months ended September 30, 2015	$ 338	$ 449	$ 464	NA	NA
Nine months ended September 30, 2014	NA	$ 898	$ 1,391	$ 766	$ 464
Nine months ended September 30, 2015	$ 675	$ 1,347	$ 1,391	$ 255	NA

3. Property and Equipment

Property and equipment consisted of the following at September 30, 2015 and December 31, 2014 (in thousands):

	September 30, 2015	December 31, 2014
Equipment	$6,960,256	$6,679,894
Oil and natural gas properties	200,822	196,234
Buildings	90,710	83,465
Land	22,528	12,038
	7,274,316	6,971,631
Less accumulated depreciation, depletion and impairment	(3,251,117)	(2,840,560)
Property and equipment, net	$4,023,199	$4,131,071

On a periodic basis, the Company evaluates its fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type (such as drilling conventional, vertical wells versus drilling longer, horizontal wells using higher specification rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to the Company's other marketed rigs are transferred to other rigs or to the Company's yards to be used as spare equipment. The remaining components of these rigs will be retired. In the quarter ended September 30, 2015, the Company identified 24 mechanical rigs and 9 non-APEX® electric rigs that will no longer be marketed. Also, the Company has 15 additional mechanical rigs that are not currently operating. Although these 15 rigs remain marketable, the Company has lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. The Company recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remain marketable but are not operating, and the write-down of excess spare rig components to their realizable values.

The Company also periodically evaluates its pressure pumping assets and in the quarter ended September 30, 2015, recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities.

The Company evaluates the recoverability of its long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable (a "triggering event"). During the first quarter of 2015, oil prices averaged $48.54 per barrel and reached a low of $43.39 per barrel on March 17, 2015. Oil prices improved during the second quarter of 2015 and averaged $57.85 per barrel. Although the price improvement was earlier than the Company projected, this improvement was generally consistent with the Company's assumption at December 31, 2014, that oil prices would improve late in 2015 and continue to improve in 2016, resulting in improved activity levels for both the contract drilling and pressure pumping businesses. During the second quarter of 2015 as oil prices increased, the Company received requests from customers to reactivate drilling rigs to resume operations in the third quarter of 2015. The Company believed this was an indication that future activity levels would be improving for both the contract drilling and pressure pumping businesses. During the third quarter of 2015, however, oil prices declined and averaged $46.42 per barrel and reached a new low for 2015 of $38.22 per barrel on August 24, 2015. With lower oil prices in August, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. In light of the Company's revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, management deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. The Company performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within its contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and the Company determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. The expected cash flows for the contract drilling segment include the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million at September 30, 2015. Rigs not under term contracts will be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon the Company's historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments are based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices. While management believes these assumptions with respect to future pricing for oil and natural gas are reasonable, actual future prices may vary significantly from the ones that were assumed. The timeframe over which oil and natural gas prices will recover is highly uncertain. Potential events that could affect the Company's assumptions regarding future prices and the timeframe for a recovery are affected by factors such as:

- market supply and demand,
- domestic and international military, political, economic and weather conditions,
- the desire and ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,

- technical advances affecting energy consumption and production,
- the price and availability of alternative fuels,
- the cost of exploring for, developing, producing and delivering oil and natural gas, and
- regulations regarding the exploration, development, production and delivery of oil and natural gas

All of these factors are beyond the Company's control. If the current lower oil and natural gas commodity price environment were to last into 2017 and beyond, the Company's actual cash flows would likely be less than the expected cash flows used in this assessment and could result in impairment charges in the future and such impairment could be material.

With respect to the long-lived assets in the Company's oil and natural gas exploration and production segment, the Company assesses the recoverability of long-lived assets each quarter due to revisions in its oil and natural gas reserve estimates and expectations about future commodity prices. The Company's analysis indicated that the carrying amounts of certain oil and natural gas properties were not recoverable at various testing dates in 2015. The Company's estimates of expected future net cash flows from impaired properties are used in measuring the fair value of such properties. The Company recorded impairment charges of $9.3 million in 2015, including $1.9 million in the quarter ended September 30, 2015, related to its oil and natural gas properties.

4. Business Segments

The Company's revenues, operating profits and identifiable assets are primarily attributable to three business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) the investment, on a non-operating working interest basis, in oil and natural gas properties. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance. Separate financial data for each of our business segments is provided in the table below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues:				
Contract drilling	$262,196	$483,307	$953,025	$1,350,296
Pressure pumping	154,407	349,996	580,752	896,834
Oil and natural gas	6,027	14,724	20,343	38,844
Total segment revenues	422,630	848,027	1,554,120	2,285,974
Elimination of intercompany revenues (a)	(379)	(2,399)	(1,409)	(4,902)
Total revenues	$422,251	$845,628	$1,552,711	$2,281,072
Income (loss) before income taxes:				
Contract drilling	$(131,256)	$12,147	$(65,692)	$148,841
Pressure pumping	(183,464)	25,208	(217,224)	51,661
Oil and natural gas	(1,824)	3,002	(10,017)	9,337
	(316,544)	40,357	(292,933)	209,839
Corporate and other	(14,333)	(13,936)	(44,519)	(42,251)

Net gain on asset disposals (b)	1,362	3,870	7,276	8,705
Interest income	323	234	924	618
Interest expense	(9,254)	(6,993)	(27,044)	(21,430)
Other	16	—	16	3
Income (loss) before income taxes	$(338,430)	$23,532	$(356,280)	$155,484

	September 30, 2015	December 31, 2014
Identifiable assets:		
Contract drilling	$3,599,607	$4,000,576
Pressure pumping	870,290	1,186,010
Oil and natural gas	37,449	50,945
Corporate and other (c)	170,820	156,480
Total assets	$4,678,166	$5,394,011

(a) Consists of contract drilling and, in 2014, pressure pumping intercompany revenues for services provided to the oil and natural gas exploration and production segment.

(b) Net gains or losses associated with the disposal of assets relate to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been separately presented and excluded from the results of specific segments.

(c) Corporate and other assets primarily include cash on hand, income tax receivables and certain deferred tax assets.

5. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of September 30, 2015 and changes for the nine months then ended are as follows (in thousands):

	Contract Drilling	Pressure Pumping	Total
Balance, December 31, 2014	$86,234	$124,561	$210,795
Changes to goodwill	—	(124,561)	(124,561)
Balance, September 30, 2015	$86,234	$—	$86,234

There were no accumulated impairment losses related to the goodwill in the contract drilling operating segment as of September 30, 2015 or December 31, 2014.

Goodwill is evaluated at least annually as of December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing have been determined to be its operating segments. The Company first determines whether it is more likely than not that the fair value of a reporting unit is less than its carrying value after considering qualitative, market and other factors. If so, then goodwill impairment is determined using a two-step impairment test. From time to time, the Company may perform the first step of the quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. The first step is to compare the fair value of an entity's reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeds its fair value, the second step of the impairment test is performed whereby the fair value of the reporting unit is allocated to its identifiable tangible and intangible assets and liabilities with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized in the amount of the shortfall.

During the first quarter of 2015, oil prices averaged $48.54 per barrel and reached a low of $43.39 per barrel on March 17, 2015. Oil prices improved during the second quarter of 2015 and averaged $57.85 per barrel. Although the price improvement was earlier than the Company projected, this improvement was generally consistent with the Company's assumption at December 31, 2014, that oil prices would improve in late 2015 and continue to improve in 2016, resulting in improved activity levels for both the contract drilling and pressure pumping businesses. During the second quarter of 2015 as oil prices increased, the Company received requests from customers to reactivate drilling rigs to resume operations in the third quarter of 2015. The Company believed this was an indication that future activity levels would be improving for both the contract drilling and pressure pumping businesses. During the third quarter of 2015, however, oil prices declined and averaged $46.42 per barrel and reached a new low for 2015 of $38.22 per barrel on August 24, 2015. With lower oil prices in August, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. In light of the

Company's revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, the Company performed a goodwill impairment test as of September 30, 2015. In completing the first step of the analysis, the fair value of each reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums.

Based on the results of the first step of the goodwill impairment test as of September 30, 2015, management concluded that no impairment was indicated in its contract drilling reporting unit; however, impairment was indicated in its pressure pumping reporting unit. In the three months ended September 30, 2015, the Company recognized an impairment charge of $125 million associated with the impairment of the goodwill of the pressure pumping reporting unit. The implied fair value of goodwill was estimated using a variety of valuation methods, including the income and market approaches. The estimate of fair value required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's pressure pumping reporting unit, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums.

Intangible Assets — Intangible assets were recorded in the pressure pumping operating segment in connection with the fourth quarter 2010 acquisition of the assets of a pressure pumping business. As a result of the purchase price allocation, the Company recorded an intangible asset related to the customer relationships acquired. The intangible asset was recorded at fair value on the date of acquisition.

The value of the customer relationships was estimated using a multi-period excess earnings model to determine the present value of the projected cash flows associated with the customers in place at the time of the acquisition and taking into account a contributory asset charge. The resulting intangible asset is being amortized on a straight-line basis over seven years. Amortization expense of approximately $911,000 was recorded in the three months ended September 30, 2015 and 2014, and amortization expense of approximately $2.7 million was recorded in the nine months ended September 30, 2015 and 2014 associated with customer relationships. The assessment of the recoverability of the pressure pumping asset group included the customer relationship intangible asset and no impairment was indicated.

The following table presents the gross carrying amount and accumulated amortization of the customer relationships as of September 30, 2015 and December 31, 2014 (in thousands):

	September 30, 2015			December 31, 2014		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$25,500	$ (18,214)	$ 7,286	$25,500	$ (15,482)	$ 10,018

6. Accrued Expenses

Accrued expenses consisted of the following at September 30, 2015 and December 31, 2014 (in thousands):

	September 30, 2015	December 31, 2014
Salaries, wages, payroll taxes and benefits	$ 35,447	$ 52,956
Workers' compensation liability	74,468	77,348
Property, sales, use and other taxes	11,873	11,644
Insurance, other than workers' compensation	13,234	9,632
Accrued interest payable	13,701	7,427
Other	31,807	14,459
	$ 180,530	$ 173,466

7. Asset Retirement Obligation

The Company records a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. This liability is included in the caption “other” in the liabilities section of the condensed consolidated balance sheet. The following table describes the changes to the Company’s asset retirement obligations during the nine months ended September 30, 2015 and 2014 (in thousands):

	Nine Months Ended September 30,	
	2015	2014
Balance at beginning of year	$5,301	$4,837
Liabilities incurred	322	411
Liabilities settled	(118)	(68)
Accretion expense	129	126
Revision in estimated costs of plugging oil and natural gas wells	—	19
Asset retirement obligation at end of period	$5,634	$5,325

8. Long Term Debt

2012 Credit Agreement — On September 27, 2012, the Company entered into a Credit Agreement (as amended, the “Credit Agreement”) with Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto. The Credit Agreement is a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility.

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time. The revolving credit facility contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million, in each case outstanding at any time.

The term loan facility provides for a loan of $100 million, which was drawn on December 24, 2012. The term loan facility is payable in quarterly principal installments, which commenced December 27, 2012. The installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the subsequent four quarterly installments and 13.75% of the original principal amount for the final four quarterly installments.

Subject to customary conditions, the Company may request that the lenders' aggregate commitments with respect to the revolving credit facility and/or the term loan facility be increased by up to $100 million, not to exceed total commitments of $700 million. The maturity date under the Credit Agreement is September 27, 2017 for both the revolving facility and the term facility.

Loans under the Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. The applicable margin on LIBOR rate loans varies from 2.25% to 3.25% and the applicable margin on base rate loans varies from 1.25% to 2.25%, in each case determined based upon the Company's debt to capitalization ratio. As of September 30, 2015 the applicable margin on LIBOR rate loans was 2.25% and the applicable margin on base rate loans was 1.25%. Based on the Company's debt to capitalization ratio at June 30, 2015, the applicable margin on LIBOR loans is 2.25% and the applicable margin on base rate loans is 1.25% as of October 1, 2015. Based on the Company's debt to capitalization ratio at September 30, 2015, the applicable margin on LIBOR loans will be 2.25% and the applicable margin on base rate loans will be 1.25% as of January 1, 2016. A letter of credit fee is payable by the Company equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

Each domestic subsidiary of the Company will unconditionally guarantee all existing and future indebtedness and liabilities of the other guarantors and the Company arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover obligations of the Company and any subsidiary of the Company arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 45%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at September 30, 2015. The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require the Company to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy of the Company, such acceleration is automatic), and (iii) require the Company to cash collateralize any outstanding letters of credit.

As of September 30, 2015, the Company had $75.0 million principal amount outstanding under the term loan facility at an interest rate of 2.625% and no amounts outstanding under the revolving credit facility. The Company currently has available borrowing capacity of $500 million under the revolving credit facility.

2015 Reimbursement Agreement — On March 16, 2015, the Company entered into a Reimbursement Agreement (the “Reimbursement Agreement”) with The Bank of Nova Scotia (“Scotiabank”), pursuant to which the Company may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of September 30, 2015, the Company had $41.3 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, the Company will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by the Company at the time of issuance at such rates and amounts as are in accordance with Scotiabank’s prevailing practice. The Company is obligated to pay to Scotiabank interest on all amounts not paid by the Company on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

The Company has also agreed that if obligations under the Credit Agreement are secured by liens on any of its or any of its subsidiaries' property, then the Company's reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015 (the "Continuing Guaranty"), the Company's payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by subsidiaries of the Company that from time to time guarantee payment under the Credit Agreement.

2015 Term Loan Agreement — On March 18, 2015, the Company entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement is a senior unsecured single-advance term loan facility pursuant to which the Company made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing is payable in quarterly principal installments, together with accrued interest, on each June 30, September 30, December 31 and March 31, commencing on June 30, 2015. Each of the first four principal installments is in an amount equal to 2.5% of the Term Loan Borrowing and each successive quarterly installment, until and including June 30, 2017, is in an amount equal to 5.0% of the Term Loan Borrowing, with the outstanding principal balance of the Term Loan Borrowing due on the maturity date under the 2015 Term Loan Agreement. The maturity date under the 2015 Term Loan Agreement is September 27, 2017. Loans under the 2015 Term Loan Agreement bear interest, at the Company's election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

Each domestic subsidiary of the Company will unconditionally guarantee all existing and future indebtedness and liabilities of the other guarantors and the Company arising under the 2015 Term Loan Agreement and other Loan Documents (as defined in the 2015 Term Loan Agreement), other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million.

The 2015 Term Loan Agreement requires quarterly compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 45%. The 2015 Term Loan Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The 2015 Term Loan Agreement generally defines the interest coverage ratio as the ratio of EBITDA of the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at September 30, 2015.

The 2015 Term Loan Agreement further provides that neither the Company nor its subsidiaries is permitted to make restricted payments unless, after giving effect to such restricted payment, its pro forma ratio of debt to EBITDA for the four prior fiscal quarters, determined as of the preceding ending quarterly period, does not exceed 2.50 to 1.00. Restricted payments are generally defined as (a) dividends and distributions made on account of equity interests of the Company or its subsidiaries and (b) payments made to redeem, repurchase or otherwise retire equity interests of the Company or its subsidiaries. Payments made solely in the form of common equity interests, made to the Company and its subsidiaries, or made in connection with the Company's long term incentive plans are not restricted payments under the 2015 Term Loan Agreement.

The 2015 Term Loan Agreement also contains customary representations, warranties, affirmative and negative covenants, and events of default. Events of default under the 2015 Term Loan Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, Loan Document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to accelerate and require the Company to repay all the outstanding amounts owed under any Loan Document (provided that in limited circumstances with respect to insolvency and bankruptcy of the Company, such acceleration is automatic).

As of September 30, 2015, the Company had $190 million principal amount outstanding under the 2015 Term Loan Agreement at a rate of 3.625%.

Senior Notes — On October 5, 2010, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.97% Series A Senior Notes due October 5, 2020 (the "Series A Notes") in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. The Company will pay interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. The Company will pay interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are senior unsecured obligations of the Company which rank equally in right of payment with all other unsubordinated indebtedness of the Company. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of the domestic subsidiaries of the Company other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at the Company's option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements. The Company must offer to prepay the notes upon the occurrence of any change of control. In addition, the Company must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for that same period. The Company was in compliance with these covenants at September 30, 2015.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if the Company defaults in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

The Company incurred approximately $2.0 million in debt issuance costs during 2015 in connection with the Reimbursement Agreement and the 2015 Term Loan Agreement. Debt issuance costs are deferred and recognized as interest expense over the term of the underlying debt. Interest expense related to the amortization of debt issuance costs was approximately $746,000 for the three months ended September 30, 2015 and $547,000 for the three months ended September 30, 2014. Interest expense related to the amortization of debt issuance costs was approximately $2.0 million for the nine months ended September 30, 2015 and $1.6 million for the nine months ended September 30, 2014.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of September 30, 2015 (in thousands):

Year ending December 31,	
2015	10,000
2016	63,750
2017	191,250
2018	—
2019	—
Thereafter	600,000
Total	$865,000

9. Commitments, Contingencies and Other Matters

As of September 30, 2015, the Company maintained letters of credit in the aggregate amount of $41.3 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of September 30, 2015, no amounts had been drawn under the letters of credit.

As of September 30, 2015, the Company had commitments to purchase approximately $114 million of major equipment for its drilling and pressure pumping businesses.

The Company's pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2016, 2017 and 2018. As of September 30, 2015, the remaining obligation under these agreements was approximately $55.4 million, of which materials with a total purchase price of approximately $1.8 million were required to be purchased during the remainder of 2015. In the event that the required minimum quantities are not purchased during any contract year, the Company could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, the Company's pressure pumping business entered into an agreement with a proppant vendor to advance up to $12.0 million to such vendor to finance the construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of September 30, 2015, advances of approximately $11.8 million had been made under this agreement and principal repayments of approximately $10.5 million had been received, resulting in a balance outstanding of approximately $1.3 million.

A $12.3 million charge related to the previously disclosed settlement of a lawsuit filed by the U.S. Equal Employment Opportunity Commission against the Company's U.S. contract drilling subsidiary was recorded in the first quarter of 2015.

Other than the matter described above, the Company is party to various legal proceedings arising in the normal course of its business; the Company does not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on its financial condition, results of operations or cash flows.

10. Stockholders' Equity

Cash Dividends — The Company paid cash dividends during the nine months ended September 30, 2014 and 2015 as follows:

2014:	Per Share	Total (in thousands)
Paid on March 27, 2014	$ 0.10	$ 14,456
Paid on June 26, 2014	0.10	14,562

Paid on September 24, 2014	0.10	14,634
Total cash dividends	$0.30	$ 43,652

2015:	Per Share	Total (in thousands)
Paid on March 25, 2015	$0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Total cash dividends	$0.30	$ 44,064

On October 21, 2015, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.10 per share to be paid on December 24, 2015 to holders of record as of December 10, 2015. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of the Company's credit facilities and other debt agreements and other factors.

On September 6, 2013, the Company's Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of the Company's common stock in open market or privately negotiated transactions. As of September 30, 2015, the Company had remaining authorization to purchase approximately $187 million of the Company's outstanding common stock under the stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

Treasury stock acquisitions during the nine months ended September 30, 2015 were as follows (dollars in thousands):

	September 30, 2015	
	Shares	Cost
Treasury shares at beginning of period	42,818,585	$899,035
Acquisitions pursuant to long-term incentive plans	380,037	7,830
Purchases pursuant to the 2013 buyback program	8,618	180
Treasury shares at end of period	43,207,240	$907,045

11. Income Taxes

The Company’s effective income tax rate was 33.8% for the nine months ended September 30, 2015, compared to 32.4% for the nine months ended September 30, 2014. The Domestic Production Activities Deduction was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008), and allows a deduction of 9% on the lesser of qualified production activities income or taxable income. For financial statement purposes, the Company expects a loss before income taxes for the year ending December 31, 2015; however, the Company currently expects to have taxable income for the year ending December 31, 2015, and the Domestic Production Activities Deduction is expected to provide a permanent tax benefit for 2015. The permanent tax benefit for 2015 is expected to be lower in 2015 due to lower expected taxable income in 2015 than in 2014. The interplay between the expected loss before income taxes for financial statement purposes and the permanent tax benefit expected to be provided by the Domestic Production Activities Deduction resulted in a higher effective income tax rate for the nine months ended September 30, 2015.

12. Fair Values of Financial Instruments

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items. These fair value estimates are considered Level 1 fair value estimates in the fair value hierarchy of fair value accounting.

The estimated fair value of the Company’s outstanding debt balances (including current portion) as of September 30, 2015 and December 31, 2014 is set forth below (in thousands):

	September 30, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Borrowings under Credit Agreement:				
Revolving credit facility	$—	$—	$303,000	$303,000
Term loan facility	75,000	75,000	82,500	82,500
2015 Term Loan	190,000	190,000	—	—
4.97% Series A Senior Notes	300,000	301,447	300,000	288,346
4.27% Series B Senior Notes	300,000	284,697	300,000	269,173
Total debt	$865,000	$851,144	$985,500	$943,019

The carrying values of the balances outstanding under the Credit Agreement and the 2015 Term Loan Agreement approximate their fair values as these instruments have a floating interest rate. The fair value of the Series A Notes and the Series B Notes at September 30, 2015 and December 31, 2014 are based on discounted cash flows associated with the respective notes using current market rates of interest at those respective dates. For the Series A Notes, the current market rates used in measuring this fair value were 4.86% at September 30, 2015 and 5.77% at December 31, 2014. For the Series B Notes, the current market rates used in measuring this fair value were 5.18% at September 30, 2015 and 6.00% at December 31, 2014. These fair value estimates are based on observable market inputs and are considered Level 2 fair value estimates in the fair value hierarchy of fair value accounting.

13. Recently Issued Accounting Standards

In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

In April 2015, the FASB issued an accounting standards update to provide guidance for the presentation of debt issuance costs. Under this guidance, debt issuance costs shall be presented in the balance sheet as a direct deduction from the carrying amount of the related debt and shall not be classified as a deferred charge. Amortization of debt issuance costs shall continue to be reported as interest expense. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (this “Report”) and other public filings and press releases by us contain “forward-looking statements” within the meaning of the Securities Act of 1933, as amended (the “Securities Act”), the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and the Private Securities Litigation Reform Act of 1995, as amended. These “forward-looking statements” involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; revenue and cost expectations and backlog; financing of operations; oil and natural gas prices; source and sufficiency of funds required for building new equipment and additional acquisitions (if further opportunities arise); impact of inflation; demand for our services; competition; equipment availability; government regulation; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historical or current facts and often use words such as “anticipates,” “believes,” “budgeted,” “continue,” “could,” “estimates,” “expects,” “intends,” “may,” “plans,” “project,” “strategy,” or “will,” or the nega and other words and expressions of similar meaning. The forward-looking statements are based on certain assumptions and analyses we make in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Forward-looking statements may be made orally or in writing, including, but not limited to, Management’s Discussion and Analysis of Financial Condition and Results of Operations included in this Report and other sections of our filings with the United States Securities and Exchange Commission (the “SEC”) under the Exchange Act and the Securities Act.

Forward-looking statements are not guarantees of future performance and a variety of factors could cause actual results to differ materially from the anticipated or expected results expressed in or suggested by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, volatility in customer spending and in oil and natural gas prices that could adversely affect demand for our services and their associated effect on rates, utilization, margins and planned capital expenditures, global economic conditions, excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction, equipment specialization and new technologies, adverse industry conditions, adverse credit and equity market conditions, difficulty in building and deploying new equipment and integrating acquisitions, shortages, delays in delivery and interruptions in supply of equipment, supplies and materials, weather, loss of key customers, liabilities from operations for which we do not have and receive full indemnification or insurance, ability to effectively identify and enter new markets, governmental regulation, ability to realize backlog, ability to retain management and field personnel and other factors. Refer to “Risk Factors” contained in Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2014 for a more complete discussion of factors that might affect our performance and financial results. You are cautioned not to place undue reliance on any of our forward-looking statements. These forward-looking statements are intended to relay our expectations about the future, and speak only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, changes in internal estimates or otherwise, except as required by law.

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

Recent Developments — Oil prices declined significantly during the second half of 2014 and continued to decline in the first quarter of 2015. The closing price of oil was as high as $105.68 per barrel during the third quarter of 2014 and during the first quarter of 2015 reached a low of $43.39 on March 17, 2015. Oil prices improved somewhat during the second quarter reaching $61.36 on June 10, 2015. However, oil prices declined during the third quarter to a low of $38.22 on August 24, 2015 and the closing price of oil was $43.19 on October 26, 2015. As a result of the prolonged decline in oil prices, our industry continues to experience a severe downturn. Although the magnitude as well as the duration of this downturn are not yet known, we believe that industry activity in both contract drilling and pressure pumping will fall further into year end and continue to fall into 2016, absent a recovery in oil prices.

Low commodity prices are negatively impacting spending by exploration and production companies. The impact of these spending reductions is evidenced by the published rig counts, which have declined by over 55% in the United States since the recent peak in October 2014.

Our rig count has also declined. During October 2014, the number of our drilling rigs operating in the United States was as high as 214, and as of September 30, 2015 we had 96 drilling rigs operating in the United States. We are continuing to receive indications of customers' intent to early terminate term contracts and some of our drilling customers are continuing to seek price reductions.

Our pressure pumping business is continuing to experience the effects of reduced spending by customers and downward pressure on pricing. We believe that pricing in the pressure pumping industry has deteriorated to levels that are not sustainable. Due to market conditions, we have stacked approximately 38% of our fracturing horsepower.

In anticipation of this downturn, we began reducing our cost structure in the fourth quarter of 2014. In 2015, we have continued to reduce our cost structure and, to date, we have reduced our drilling headcount at a rate generally proportionate with the reduction in our rig count. In pressure pumping, we have reduced our headcount and obtained lower prices on many products and services that we use. We have also reduced our capital expenditure plans for the remainder of 2015, and although we have not completed our 2016 budget, we expect our capital expenditures to primarily consist of maintenance capital, as we do not expect to build any new rigs or purchase any new fracturing horsepower in 2016. We plan to continue to adjust our cost structure in line with our level of operating activity.

We expect that our term contract coverage in contract drilling and scalability with respect to labor and other operating costs in contract drilling and pressure pumping should position us to weather this downturn. Nevertheless, we expect to experience further declines in both activity and pricing in the contract drilling and pressure pumping businesses. In the event oil prices remain depressed for a sustained period, or decline further, these declines could have a material adverse effect on our business, financial condition and results of operations.

Management Overview — We are a leading provider of services to the North American oil and natural gas industry. Our services primarily involve the drilling, on a contract basis, of land-based oil and natural gas wells and pressure pumping services. In addition to these services, we also invest, on a non-operating working interest basis, in oil and natural gas properties.

We operate land-based drilling rigs in oil and natural gas producing regions of the continental United States and western Canada. There continues to be uncertainty with respect to the global economic environment, and oil and natural gas prices are depressed. During the third quarter of 2015, our average number of rigs operating in the United States was 105 compared to an average of 209 drilling rigs operating during the same period in 2014. During the third quarter of 2015, our average number of rigs operating in Canada was 4 compared to an average of 10 drilling rigs operating during the third quarter of 2014.

We have addressed our customers' needs for drilling horizontal wells in shale and other unconventional resource plays by expanding our areas of operation and improving the capabilities of our drilling fleet during the last several years. As of September 30, 2015, our rig fleet included 160 APEX® rigs. We expect to add one additional new APEX® rig under contract to our fleet during the fourth quarter of 2015.

In connection with the development of horizontal shale and other unconventional resource plays, we added equipment to perform service intensive fracturing jobs. As of September 30, 2015, we had approximately 1.1 million hydraulic horsepower in our pressure pumping fleet. We have increased the horsepower of our pressure pumping fleet by more than eight-fold since the beginning of 2009, although we have not ordered or committed to purchase any new horsepower since October 2014 and there is currently no new horsepower on order. In recent years, low natural gas prices and the industry-wide addition of new pressure pumping equipment to the marketplace led to an excess supply of pressure pumping equipment in North America.

We maintain a backlog of commitments for contract drilling revenues under term contracts, which we define as contracts with a fixed term of six months or more. Our backlog as of September 30, 2015 was approximately $801 million. We generally calculate our backlog by multiplying the dayrate under our term drilling contracts by the number of days remaining under the contract. The calculation does not include any revenues related to other fees such as for mobilization, demobilization and customer reimbursables, nor does it include potential reductions in rates for unscheduled standby or during periods in which the rig is moving or incurring maintenance and repair time in excess of what is permitted under the drilling contract. In addition, generally our term drilling contracts are subject to termination by the customer on short notice and provide for an early termination payment to us in the event that the contract is terminated by the customer. For contracts that we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period we expect to receive the lower rate.

For the nine months ended September 30, 2015 and 2014, our operating revenues consisted of the following (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015		2014		2015		2014	
Contract drilling	$261,817	62 %	$482,212	57 %	$951,616	61 %	$1,346,698	59 %
Pressure pumping	154,407	37 %	348,692	41 %	580,752	38 %	895,530	39 %
Oil and natural gas	6,027	1 %	14,724	2 %	20,343	1 %	38,844	2 %
	$422,251	100%	$845,628	100%	$1,552,711	100%	$2,281,072	100%

Generally, the profitability of our business is impacted most by two primary factors in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During the third quarter of 2015, our average number of rigs operating was 105 in the United States and four in Canada compared to 209 in the United States and 10 in Canada in the third quarter of 2014. Our average revenue per operating day was $26,010 in the third quarter of 2015, including $28.9 million of early termination revenue, compared to $24,010 in the third quarter of 2014. Consolidated net loss for the third quarter of 2015 was $226 million compared to consolidated net income of $16.0 million for the third quarter of 2014. The financial results for the three months ended September 30, 2015 include pretax non-cash charges totaling $280 million. These charges include $125 million from the impairment of all goodwill associated with our pressure pumping business, $131 million from the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components, $22.0 million from the write-down of pressure pumping equipment and closed facilities and $1.9 million related to the impairment of certain oil and natural gas properties.

For the three months ended September 30, 2014, the financial results include a pretax non-cash charge of $77.9 million related to the retirement of mechanical rigs and the write-off of excess spare components.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our services. Conversely, in periods when these commodity prices deteriorate, the demand for our services generally weakens, and we experience downward pressure on pricing for our services. In September 2015, our average number of rigs operating was 99 in the United States and four in Canada. We are also highly impacted by operational risks, competition, the availability of excess equipment, labor issues, weather and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations. Please see “Risk Factors” included in Part I of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

Our liquidity as of September 30, 2015 included approximately $110 million in working capital and $500 million available under our revolving credit facility. We believe our current liquidity, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain our existing equipment, service our debt and pay cash dividends. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy the needs through a combination of working capital, cash flows from operating activities, borrowing capacity under our revolving credit facility, debt financing and equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Commitments and Contingencies — As of September 30, 2015, we maintained letters of credit in the aggregate amount of $41.3 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of September 30, 2015, no amounts had been drawn under the letters of credit.

As of September 30, 2015, we had commitments to purchase approximately $114 million of major equipment for our drilling and pressure pumping businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2016, 2017 and 2018. As of September 30, 2015, the remaining obligation under these agreements was approximately $55.4 million, of which materials with a total purchase price of approximately $1.8 million were required to be purchased during the remainder of 2015. In the event that the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, our pressure pumping business entered into an agreement with a proppant vendor to advance up to \$12.0 million to such vendor to finance its construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of September 30, 2015, advances of approximately \$11.8 million had been made under this agreement and repayments of approximately \$10.5 million had been received resulting in a balance outstanding of approximately \$1.3 million.

A \$12.3 million charge related to the previously disclosed settlement of a lawsuit filed by the U.S. Equal Employment Opportunity Commission against our U.S. contract drilling subsidiary was recorded in the first quarter of 2015.

Trading and Investing — We have not engaged in trading activities that include high-risk securities, such as derivatives and non-exchange traded contracts. We invest cash primarily in highly liquid, short-term investments such as overnight deposits and money market accounts.

Description of Business — We conduct our contract drilling operations primarily in the continental United States and western Canada. We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian region. Pressure pumping services are primarily well stimulation and cementing for completion of new wells and remedial work on existing wells. We also invest in oil and natural gas assets as a non-operating working interest owner. Our oil and natural gas working interests are located primarily in Texas and New Mexico.

The North American oil and natural gas services industry is cyclical and at times experiences downturns in demand. During these periods, there have been substantially more drilling rigs and pressure pumping equipment available than necessary to meet demand. As a result, drilling and pressure pumping contractors have had difficulty sustaining profit margins and, at times, have incurred losses during the downturn periods. The North American oil and natural gas services industry is currently experiencing a severe downturn.

Construction of new technology drilling rigs has increased in recent years. The addition of new technology drilling rigs to the market, combined with a reduction in the drilling of vertical wells, has resulted in excess capacity of older technology drilling rigs. Similarly, the substantial increase in unconventional resource plays led to higher demand for pressure pumping services, and there has been a significant increase in the construction of new pressure pumping equipment across the industry. As a result of the decline in oil and natural gas prices and the construction of new equipment, there is an excess of new technology drilling rigs and pressure pumping equipment available. In circumstances of excess capacity, providers of drilling and pressure pumping services have difficulty sustaining profit margins and may sustain losses during downturn periods. We cannot predict either the future level of demand for our contract drilling or pressure pumping services or future conditions in the oil and natural gas contract drilling or pressure pumping businesses.

In addition, unconventional resource plays have substantially increased and some drilling rigs are not capable of drilling these wells efficiently. Accordingly, the utilization of some older technology drilling rigs has been hampered by their lack of capability to efficiently compete for this work. Other ongoing factors which could continue to adversely affect utilization rates and pricing, even in an environment of high oil and natural gas prices and increased drilling activity, include:

- movement of drilling rigs from region to region,
- reactivation of land-based drilling rigs, or
- construction of new technology drilling rigs.

Critical Accounting Policies

In addition to established accounting policies, our condensed consolidated financial statements are impacted by certain estimates and assumptions made by management. No changes in our critical accounting policies have occurred since the filing of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

Liquidity and Capital Resources

Our liquidity as of September 30, 2015 included approximately $110 million in working capital and $500 million available under our revolving credit facility. We believe our current liquidity, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain our existing equipment, service our debt and pay cash dividends. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash flows from operating activities, borrowing capacity under our revolving credit facility, debt financing and equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

During the nine months ended September 30, 2015, our sources of cash flow included:

- $806 million from operating activities,
- $200 million in borrowings under the new term loan, and
- $15.9 million in proceeds from the disposal of property and equipment.

During the nine months ended September 30, 2015, we used a net of $303 million to pay off our revolving credit facility, $44.1 million to pay dividends on our common stock, $17.5 million to repay long-term debt, $8.0 million to acquire shares of our common stock, $2.0 million to pay debt issuance costs and $608 million:

- to build and to acquire components to build new drilling rigs and to purchase new pressure pumping equipment,
- to make capital expenditures for the betterment and refurbishment of existing drilling rigs and pressure pumping equipment,
- to acquire and procure equipment and facilities to support our drilling and pressure pumping operations, and
- to fund investments in oil and natural gas properties on a non-operating working interest basis.

We paid cash dividends during the nine months ended September 30, 2015 as follows:

	Per Share	Total (in thousands)
Paid on March 25, 2015	$0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Total cash dividends	$0.30	$ 44,064

On October 21, 2015, our Board of Directors approved a cash dividend on our common stock in the amount of $0.10 per share to be paid on December 24, 2015 to holders of record as of December 10, 2015. The amount and timing of all future dividend payments, if any, is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other debt agreements and other factors.

On September 6, 2013, our Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of our common stock in open market or privately negotiated transactions. As of September 30, 2015, we had remaining authorization to purchase approximately $187 million of our outstanding common stock under the stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

Treasury stock acquisitions during the nine months ended September 30, 2015 were as follows (dollars in thousands):

	September 30, 2015	
	Shares	Cost
Treasury shares at beginning of period	42,818,585	$899,035
Acquisitions pursuant to long-term incentive plans	380,037	7,830
Purchases pursuant to the 2013 buyback program	8,618	180
Treasury shares at end of period	43,207,240	$907,045

2012 Credit Agreement — On September 27, 2012, we entered into a Credit Agreement (as amended, the “Credit Agreement”). The Credit Agreement is a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility.

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time. The revolving credit facility contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million, in each case outstanding at any time.

The term loan facility provides for a loan of $100 million, which was drawn on December 24, 2012. The term loan facility is payable in quarterly principal installments, which commenced December 27, 2012. The installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the subsequent four quarterly installments and 13.75% of the original principal amount for the final four quarterly installments.

Subject to customary conditions, we may request that the lenders' aggregate commitments with respect to the revolving credit facility and/or the term loan facility be increased by up to $100 million, not to exceed total commitments of $700 million. The maturity date under the Credit Agreement is September 27, 2017 for both the revolving facility and the term facility.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. The applicable margin on LIBOR rate loans varies from 2.25% to 3.25% and the applicable margin on base rate loans varies from 1.25% to 2.25%, in each case determined based upon our debt to capitalization ratio. As of September 30, 2015, the applicable margin on LIBOR rate loans was 2.25% and the applicable margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at June 30, 2015, the applicable margin on LIBOR loans is 2.25% and the applicable margin on base rate loans is 1.25% as of October 1, 2015. Based on our debt to capitalization ratio at September 30, 2015, the applicable margin on LIBOR loans will be 2.25% and the applicable margin on base rate loans will be 1.25% as of January 1, 2016. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

Each of our domestic subsidiaries will unconditionally guarantee all existing and future indebtedness and liabilities of the other guarantors and us arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover our obligations and those of any of our subsidiaries arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of EBITDA of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these financial covenants as of September 30, 2015. The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require us to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy, such acceleration is automatic), and (iii) require us to cash collateralize any outstanding letters of credit.

As of September 30, 2015, we had $75.0 million principal amount outstanding under the term loan facility at an interest rate of 2.625% and no amounts outstanding under the revolving credit facility. We currently have available borrowing capacity of $500 million under the revolving credit facility.

2015 Reimbursement Agreement — On March 16, 2015, we entered into a Reimbursement Agreement (the "Reimbursement Agreement") with The Bank of Nova Scotia ("Scotiabank"), pursuant to which we may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of September 30, 2015, we had $41.3 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, we will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by us at the time of issuance at such rates and amounts as are in accordance with Scotiabank's prevailing practice. We are obligated to pay to Scotiabank interest on all amounts not paid on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

We have also agreed that if obligations under the Credit Agreement are secured by liens on any of our subsidiaries' property, then our reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015 (the "Continuing Guaranty"), our payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by our subsidiaries that from time to time guarantee payment under the Credit Agreement.

2015 Term Loan Agreement — On March 18, 2015, we entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement is a senior unsecured single-advance term loan facility pursuant to which we made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing is payable in quarterly principal installments, together with accrued interest, on each June 30, September 30, December 31 and March 31, commencing on June 30, 2015. Each of the first four principal installments is in an amount equal to 2.5% of the Term Loan Borrowing and each successive quarterly installment, until and including June 30, 2017, is in an amount equal to 5.0% of the Term Loan Borrowing, with the outstanding principal balance of the Term Loan Borrowing due on the maturity date under the 2015 Term Loan Agreement. The maturity date under the 2015 Term Loan Agreement is September 27, 2017. Loans under the 2015 Term Loan Agreement bear interest, at our election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

Each of our domestic subsidiaries will unconditionally guarantee all existing and future indebtedness and liabilities of the other guarantors and us arising under the 2015 Term Loan Agreement and other Loan Documents (as defined in the 2015 Term Loan Agreement), other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million.

The 2015 Term Loan Agreement requires quarterly compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45%. The 2015 Term Loan Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The 2015 Term Loan Agreement generally defines the interest coverage ratio as the ratio of EBITDA of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these financial covenants as of September 30, 2015.

The 2015 Term Loan Agreement further provides that neither we nor our subsidiaries are permitted to make restricted payments unless, after giving effect to such restricted payment, its pro forma ratio of debt to EBITDA for the four prior fiscal quarters, determined as of the preceding ending quarterly period, does not exceed 2.50 to 1.00. Restricted payments are generally defined as (a) dividends and distributions made on account of our equity interests or our subsidiaries and (b) payments made to redeem, repurchase or otherwise retire our equity interests or our subsidiaries. Payments made solely in the form of common equity interests, made to us and our subsidiaries, or made in connection with the our long term incentive plans are not restricted payments under the 2015 Term Loan Agreement.

The 2015 Term Loan Agreement also contains customary representations, warranties, affirmative and negative covenants, and events of default. Events of default under the 2015 Term Loan Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, Loan Document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to accelerate and require us to repay all the outstanding amounts owed under any Loan Document (provided that in limited circumstances with respect to insolvency and bankruptcy, such acceleration is automatic).

As of September 30, 2015, we had $190 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 3.625%.

On October 5, 2010, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.97% Series A Senior Notes due October 5, 2020 (the “Series A Notes”) in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. We pay interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. We pay interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are senior unsecured obligations which rank equally in right of payment with all of our other unsubordinated indebtedness. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of our domestic subsidiaries other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at our option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements. We must offer to prepay the notes upon the occurrence of any change of control. In addition, we must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. We were in compliance with these financial covenants as of September 30, 2015. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if we default in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

Our liquidity as of September 30, 2015 included approximately $110 million in working capital and $500 million available under our revolving credit facility. We believe our current liquidity together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain our existing equipment, service our debt and pay cash dividends. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash flows from operating activities, borrowing capacity under our revolving credit facility, debt financing and equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Results of Operations

The following tables summarize operations by business segment for the three months ended September 30, 2015 and 2014:

Contract Drilling	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$261,817	$482,212	(45.7)%
Direct operating costs	136,718	278,195	(50.9)%
Margin (1)	125,099	204,017	(38.7)%
Selling, general and administrative	1,599	1,213	31.8 %
Depreciation, amortization and impairment	254,756	190,657	33.6 %
Operating income (loss)	$(131,256)	$12,147	N/A
Operating days	10,067	20,084	(49.9)%
Average revenue per operating day	$26.01	$24.01	8.3 %
Average direct operating costs per operating day	$13.58	$13.85	(1.9)%
Average margin per operating day (1)	$12.43	$10.16	22.3 %
Average rigs operating	109	218	(50.0)%
Capital expenditures	$111,514	$209,769	(46.8)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenue per operating day and average margin per operating day were higher in 2015 due to early termination revenues of approximately $28.9 million. Depreciation, amortization and impairment expense for 2015 includes a charge of $131 million related to the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components. Depreciation, amortization and impairment expense for 2014 includes a charge of $77.9 million related to the retirement of mechanical drilling rigs and the write-off of excess spare mechanical rig components. The increase in depreciation expense also reflects significant capital expenditures incurred in recent years to build new drilling rigs, to modify and upgrade existing drilling rigs and to acquire additional related equipment such as top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment.

Pressure Pumping	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$154,407	$348,692	(55.7)%
Direct operating costs	138,597	281,016	(50.7)%
Margin (1)	15,810	67,676	(76.6)%
Selling, general and administrative	4,019	4,881	(17.7)%
Depreciation, amortization and impairment	70,694	37,587	88.1%
Impairment of goodwill	124,561	—	N/A
Operating income (loss)	$(183,464)	$25,208	N/A
Fracturing jobs	137	358	(61.7)%
Other jobs	517	1,228	(57.9)%
Total jobs	654	1,586	(58.8)%
Average revenue per fracturing job	$1,081.14	$913.88	18.3%
Average revenue per other job	$12.17	$17.53	(30.6)%
Average revenue per total job	$236.10	$219.86	7.4%
Average direct operating costs per total job	$211.92	$177.19	19.6%
Average margin per total job (1)	$24.17	$42.67	(43.4)%
Margin as a percentage of revenues (1)	10.2%	19.4%	(47.4)%
Capital expenditures and acquisitions	$29,409	$65,620	(55.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs decreased primarily due to a decrease in the number of jobs, although the average size of the fracturing jobs has increased. Average revenue per fracturing job and average direct operating costs per total job increased as a result of the increased size of the jobs in 2015 as compared to 2014. However, the total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Depreciation, amortization and impairment expense for 2015 includes a charge of $22.0 million related to the write-down of pressure pumping equipment and closed facilities. There were no similar charges in 2014. Depreciation expense also increased due to capital expenditures and acquisitions. All of the goodwill associated with our pressure pumping business was impaired during 2015.

Oil and Natural Gas Production and Exploration	2015	2014	% Change
	(Dollars in thousands)		
Revenues-Oil	$5,278	$13,299	(60.3)%
Revenues - Natural gas and liquids	749	1,425	(47.4)%
Revenues-Total	6,027	14,724	(59.1)%
Direct operating costs	2,519	3,275	(23.1)%
Margin (1)	3,508	11,449	(69.4)%
Depletion and impairment	5,332	8,447	(36.9)%
Operating income (loss)	$(1,824)	$3,002	N/A
Capital expenditures	$2,890	$9,489	(69.5)%

(1) Margin is defined as revenues less direct operating costs and excludes depletion and impairment.

Revenues decreased as a result of lower commodity prices and lower oil production. Direct operating costs include a reduction in taxes due to lower revenues. Depletion and impairment expense in 2015 includes approximately $1.9 million of oil and natural gas property impairments compared to approximately $2.2 million of oil and natural gas property impairments in 2014. Depletion decreased due primarily to increased reserve estimates in certain fields.

Corporate and Other	2015	2014	% Change
	(Dollars in thousands)		
Selling, general and administrative	$12,964	$12,802	1.3 %
Depreciation	$1,369	$1,134	20.7 %
Net (gain) loss on asset disposals	$(1,362)	$(3,870)	(64.8)%
Interest income	$323	$234	38.0 %
Interest expense	$9,254	$6,993	32.3 %
Other income	$16	$—	N/A
Capital expenditures	$774	$875	(11.5)%

Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Interest expense increased primarily due to borrowings under the 2015 Term Loan Agreement.

The following tables summarize operations by business segment for the nine months ended September 30, 2015 and 2014:

Contract Drilling	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$951,616	$1,346,698	(29.3)%
Direct operating costs	503,376	784,572	(35.8)%
Margin (1)	448,240	562,126	(20.3)%
Selling, general and administrative	16,717	4,452	275.5 %
Depreciation, amortization and impairment	497,215	408,833	21.6 %
Operating income (loss)	$(65,692)	$148,841	N/A
Operating days	36,798	56,861	(35.3)%
Average revenue per operating day	$25.86	$23.68	9.2 %
Average direct operating costs per operating day	$13.68	$13.80	(0.9)%
Average margin per operating day (1)	$12.18	$9.89	23.2 %
Average rigs operating	135	208	(35.1)%
Capital expenditures	$422,876	$546,609	(22.6)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenue per operating day and average margin per operating day were higher in 2015 due to higher average dayrates and the early termination revenues of approximately $60.3 million. Selling, general and administrative expenses for 2015 includes a $12.3 million charge related to a previously disclosed legal settlement. Depreciation, amortization and impairment expense for 2015 includes a charge of $131 million related to the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components. Depreciation, amortization and impairment expense for 2014 includes a charge of $77.9 million related to the retirement of mechanical drilling rigs and the write-off of excess spare mechanical rig components. The increase in depreciation expense also reflects significant capital expenditures incurred in recent years to build new drilling rigs, to modify and upgrade existing drilling rigs and to acquire additional related equipment such as top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment.

Pressure Pumping	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$580,752	$895,530	(35.1)%
Direct operating costs	494,078	722,801	(31.6)%
Margin (1)	86,674	172,729	(49.8)%
Selling, general and administrative	13,463	14,816	(9.1)%
Depreciation, amortization and impairment	165,874	106,252	56.1 %
Impairment of goodwill	124,561	—	N/A
Operating income (loss)	$(217,224)	$51,661	N/A
Fracturing jobs	501	872	(42.5)%
Other jobs	1,670	3,166	(47.3)%
Total jobs	2,171	4,038	(46.2)%
Average revenue per fracturing job	$1,108.22	$960.55	15.4 %
Average revenue per other job	$15.29	$18.30	(16.4)%
Average revenue per total job	$267.50	$221.78	20.6 %
Average direct operating costs per total job	$227.58	$179.00	27.1 %
Average margin per total job (1)	$39.92	$42.78	(6.7)%
Margin as a percentage of revenues (1)	14.9 %	19.3 %	(22.8)%
Capital expenditures and acquisitions	$169,228	$198,103	(14.6)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs decreased primarily due to a decrease in the number of jobs, although the average size of the fracturing jobs has increased. Average revenue per fracturing job and average direct operating costs per total job increased as a result of the increased size of the jobs in 2015 as compared to 2014. However, the total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Depreciation, amortization and impairment expense for 2015 includes a charge of $22.0 million related to the write-down of pressure pumping equipment and closed facilities. There were no similar charges in 2014. Depreciation expense also increased due to capital expenditures and acquisitions. All of the goodwill associated with our pressure pumping business was impaired during 2015.

Oil and Natural Gas Production and Exploration	2015	2014	% Change
	(Dollars in thousands)		
Revenues-Oil	$18,233	$34,377	(47.0)%
Revenues - Natural gas and liquids	2,110	4,467	(52.8)%
Revenues-Total	20,343	38,844	(47.6)%
Direct operating costs	8,096	9,421	(14.1)%
Margin (1)	12,247	29,423	(58.4)%
Depletion and impairment	22,264	20,086	10.8 %
Operating income (loss)	$(10,017)	$9,337	N/A
Capital expenditures	$14,094	$26,915	(47.6)%

(1) Margin is defined as revenues less direct operating costs and excludes depletion and impairment.

Oil and natural gas and liquids revenues decreased as a result of lower commodity prices partially offset by higher oil and natural gas and liquids production. Direct operating costs include a reduction in taxes due to lower revenues. Depletion and impairment expense in 2015 includes approximately $9.3 million of oil and natural gas property impairments compared to approximately $4.1 million of oil and natural gas property impairments in 2014.

Corporate and Other	2015	2014	% Change	
	(Dollars in thousands)			
Selling, general and administrative	$40,415	$38,849	4.0	%
Depreciation	$4,104	$3,402	20.6	%
Net (gain) loss on asset disposals	$(7,276)	$(8,705)	(16.4	)%
Interest income	$924	$618	49.5	%
Interest expense	$27,044	$21,430	26.2	%
Other income	$16	$3	433.3	%
Capital expenditures	$2,022	$2,164	(6.6	)%

Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Interest expense increased primarily due to borrowings under the 2015 Term Loan Agreement.

Adjusted EBITDA

Adjusted earnings before interest, taxes, depreciation and amortization ("Adjusted EBITDA") is not defined by accounting principles generally accepted in the United States of America ("U.S. GAAP"). We define Adjusted EBITDA as net income (loss) plus net interest expense, income tax expense (benefit) and depreciation, depletion, amortization and impairment expense. We present Adjusted EBITDA (a non-U.S. GAAP measure) because we believe it provides to both management and investors additional information with respect to both the performance of our fundamental business activities and our ability to meet our capital expenditures and working capital requirements. Adjusted EBITDA should not be construed as an alternative to the U.S. GAAP measures of net income (loss) or operating cash flow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(225,978)	$15,976	$(235,828)	$105,081
Income tax expense (benefit)	(112,452)	7,556	(120,452)	50,403
Net interest expense	8,931	6,759	26,120	20,812
Depreciation, depletion, amortization and impairment	332,151	237,825	689,457	538,573
Impairment of goodwill	124,561	—	124,561	—
Adjusted EBITDA	$127,213	$268,116	$483,858	$714,869

Income Taxes

Our effective income tax rate was 33.8% for the nine months ended September 30, 2015, compared to 32.4% for the nine months ended September 30, 2014. The Domestic Production Activities Deduction was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008), and allows a deduction of 9% on the lesser of qualified production activities income or taxable income. For financial statement purposes, we expect a loss before income taxes for the year ending December 31, 2015; however, we currently expect to have taxable income for the year ending December 31, 2015, and the Domestic Production Activities Deduction is expected to provide a permanent tax benefit for 2015. The permanent tax benefit for 2015 is expected to be lower in 2015 due to lower expected taxable income in 2015 than in 2014. The interplay between the expected loss before income taxes for financial statement purposes and the permanent tax benefit expected to be provided by the Domestic Production Activities Deduction resulted in a higher effective income tax rate for the nine months ended September 30, 2015.

Recently Issued Accounting Standards

In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

In April 2015, the FASB issued an accounting standards update to provide guidance for the presentation of debt issuance costs. Under this guidance, debt issuance costs shall be presented in the balance sheet as a direct deduction from the carrying amount of the related debt and shall not be classified as a deferred charge. Amortization of debt issuance costs shall continue to be reported as interest expense. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

Volatility of Oil and Natural Gas Prices and its Impact on Operations and Financial Condition

Our revenue, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by many factors beyond our control. During the nine months ended September 30, 2014, oil prices averaged $99.96 per barrel, natural gas prices averaged $4.59 per Mcf and demand for drilling and pressure pumping activities increased. During the three months ended December 31, 2014, drilling activity slowed as oil prices averaged $73.16 per barrel and natural gas prices averaged $3.80 per Mcf. During the first quarter of 2015, oil prices averaged $48.54 per barrel and natural gas prices averaged $2.90 per Mcf. During the second quarter of 2015, oil prices averaged $57.85 per barrel and natural gas prices averaged $2.75 per Mcf. During the third quarter of 2015, oil prices averaged $46.42 per barrel and natural gas prices averaged $2.76 per Mcf. As a result, drilling and pressure pumping activity has significantly decreased since December 31, 2014. Our average number of rigs operating remains well below the number of our available rigs and a significant amount of our pressure pumping equipment is stacked. Given current oil and natural gas pricing and existing market trends, we expect our average number of rigs operating and the number of pressure pumping jobs to continue to decline during the fourth quarter of 2015.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Continued low market prices for oil and natural gas will likely result in further decreased demand for our drilling rigs and pressure pumping services and adversely affect our operating results, financial condition and cash flows. Even during periods of high prices for oil and natural gas, companies exploring for oil and natural gas may cancel or curtail programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons, which could reduce demand for our drilling rigs and pressure pumping services.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

We currently have exposure to interest rate market risk associated with any borrowings that we have under the Credit Agreement, the 2015 Term Loan Agreement and the Reimbursement Agreement.

Under the Credit Agreement, interest is paid on the outstanding principal amount of borrowings at a floating rate based on, at our election, LIBOR or a base rate. The margin on LIBOR loans ranges from 2.25% to 3.25% and the margin on base rate loans ranges from 1.25% to 2.25%, based on our debt to capitalization ratio. At September 30, 2015, the margin on LIBOR loans was 2.25% and the margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at June 30, 2015, the applicable margin on LIBOR loans is 2.25% and the applicable margin on base rate loans is 1.25% as of October 1, 2015. Based on our debt to capitalization ratio at September 30, 2015, the applicable margin on LIBOR loans will be 2.25% and the applicable margin on base rate loans will be 1.25% as of January 1, 2016. As of September 30, 2015, we had no amounts outstanding under our revolving credit facility and $75.0 million outstanding under our term loan facility at an interest rate of 2.625%. The interest rate on the borrowings outstanding under our revolving credit and term loan facilities is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate.

Loans under the 2015 Term Loan Agreement bear interest, at our election, at the per annum rate of LIBOR plus 3.25% or base rate plus 2.25%. As of September 30, 2015, we had $190 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 3.625%.

Under the Reimbursement Agreement, we will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. We are obligated to pay to Scotiabank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of September 30, 2015, no amounts had been disbursed under any letters of credit.

We conduct a portion of our business in Canadian dollars through our Canadian land-based drilling operations. The exchange rate between Canadian dollars and U.S. dollars has fluctuated during the last several years. If the value of the Canadian dollar against the U.S. dollar weakens, revenues and earnings of our Canadian operations will be reduced and the value of our Canadian net assets will decline when they are translated to U.S. dollars. This currency risk is not material to our results of operations or financial condition.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures — We maintain disclosure controls and procedures (as such terms are defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act), designed to ensure that the information required to be disclosed in the reports that we file with the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10 Q. Based on that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of September 30, 2015.

Changes in Internal Control Over Financial Reporting —There were no changes in our internal control over financial reporting during our most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act.

PART II — OTHER INFORMATION

ITEM 1. Legal Proceedings

We are party to various legal proceedings arising in the normal course of our business; we do not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows. See Note 9 to our unaudited condensed consolidated financial statements in Item 1 of Part I – Financial Information.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

The table below sets forth the information with respect to purchases of our common stock made by us during the quarter ended September 30, 2015.

Period Covered	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in thousands)(1)
July 2015	—	—	—	$ 186,836
August 2015	—	—	—	$ 186,836
September 2015	—	—	—	$ 186,836
Total	—	—	—	$ 186,836

(1) On September 9, 2013, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $200 million of our common stock in open market or privately negotiated transactions.

ITEM 5. Other Information

On October 21, 2015, we amended our note purchase agreements for both the Series A Notes and Series B Notes to, among other things, conform certain provisions of these agreements with Amendment No. 1 to the Credit Agreement, which we entered into on January 9, 2015. These conforming changes in the note purchase agreements (i) replace the definition of a change of control, (ii) exempt from the requirement to become additional guarantors certain subsidiaries that are not required to become additional guarantors under the Credit Agreement and (iii) release Patterson-UTI Drilling International, Inc., one of our subsidiaries, from its obligations under each guaranty related to the note purchase agreements. The above description is qualified in its entirety by reference to the complete text of the amendments to the note purchase agreements filed as Exhibits 10.1 and 10.2 hereto, which is incorporated herein by reference.

ITEM 6. Exhibits

The following exhibits are filed herewith or incorporated by reference, as indicated:

3.1	Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.2	Amendment to Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.3	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).
10.1*	Amendment No. 1 to Purchase Agreement, dated as of October 22, 2015, by and among the Company, certain subsidiaries of the Company party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated October 5, 2010).
10.2*	Amendment No. 1 to Purchase Agreement, dated as of October 22, 2015, by and among the Company, certain subsidiaries of the Company and party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated June 14, 2012).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following materials from Patterson-UTI Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statement of Changes in Stockholders' Equity, (v) the Condensed Consolidated Statements of Cash Flows, and (vi) Notes to Condensed Consolidated Financial Statements.

* filed herewith

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PATTERSON-UTI ENERGY, INC.

By: /s/ John E. Vollmer III
John E. Vollmer III
Senior Vice President – Corporate Development,
Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer and Duly Authorized Officer)

Date: October 28, 2015