PATTERSON UTI ENERGY INC
Form 10-Q
August 01, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2011

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 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 x 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 x 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	x	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 x

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

155,650,500 shares of common stock, $0.01 par value, as of July 29, 2011

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

PART I FINANCIAL INFORMATION

PART II OTHER INFORMATION

PART I   FINANCIAL INFORMATION

ITEM 1. ***Financial Statements***

The following unaudited 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

CONSOLIDATED BALANCE SHEETS

(unaudited, in thousands, except share data)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 64,584	$ 27,612
Accounts receivable, net of allowance for doubtful accounts of $4,878 and $5,114 at June 30, 2011 and December 31, 2010, respectively	406,247	337,167
Federal and state income taxes receivable	1,310	75,062
Inventory	23,486	17,215
Deferred tax assets, net	75,796	26,815
Assets held for sale		23,370
Other	58,727	50,169
Total current assets	630,150	557,410
Property and equipment, net	2,890,668	2,620,900
Goodwill and intangible assets	177,628	179,683
Deposits on equipment purchases	66,303	51,084
Other	12,840	13,954
Total assets	$ 3,777,589	$ 3,423,031
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 230,495	$ 162,400
Accrued expenses	158,258	147,315
Current portion of long-term debt	8,750	6,250
Total current liabilities	397,503	315,965
Long-term debt	387,500	392,500
Deferred tax liabilities, net	630,737	511,422
Other	10,789	15,537
Total liabilities	1,426,529	1,235,424
Commitments and contingencies (see Note 11)		
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 183,043,921 and 181,537,568 issued and 155,561,314 and 154,193,754 outstanding at June 30, 2011 and December 31, 2010, respectively	1,830	1,815
Additional paid-in capital	824,725	796,641
Retained earnings	2,125,409	1,987,999
Accumulated other comprehensive income	23,757	21,597

Treasury stock, at cost, 27,482,607 shares and 27,343,814 shares at June 30, 2011 and December 31, 2010, respectively	(624,661)	(620,445)
Total stockholders equity	2,351,060	2,187,607
Total liabilities and stockholders equity	$ 3,777,589	$ 3,423,031

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited, in thousands, except per share data)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating revenues:				
Contract drilling	$ 386,479	$ 239,966	$ 763,837	$ 450,711
Pressure pumping	200,131	59,364	379,790	113,115
Oil and natural gas	13,454	7,662	23,841	14,764
Total operating revenues	600,064	306,992	1,167,468	578,590
Operating costs and expenses:				
Contract drilling	218,754	149,303	437,453	284,449
Pressure pumping	128,866	41,965	247,441	81,096
Oil and natural gas	2,103	1,780	4,100	3,842
Depreciation, depletion, amortization and impairment	102,749	78,783	198,964	154,499
Selling, general and administrative	16,749	12,343	32,724	23,806
Net gain on asset disposals	(1,017)	(21,939)	(2,621)	(21,690)
Provision for bad debts		(1,000)		(1,000)
Total operating costs and expenses	468,204	261,235	918,061	525,002
Operating income	131,860	45,757	249,407	53,588
Other income (expense):				
Interest income	45	1,380	88	1,567
Interest expense	(3,514)	(1,383)	(7,403)	(2,784)
Other	78	174	197	249
Total other income (expense)	(3,391)	171	(7,118)	(968)
Income from continuing operations before income taxes	128,469	45,928	242,289	52,620
Income tax expense (benefit):				
Current	15,449	1,935	19,031	(2,482)
Deferred	31,382	14,465	70,001	21,388
Total income tax expense	46,831	16,400	89,032	18,906
Income from continuing operations	81,638	29,528	153,257	33,714
Loss from discontinued operations, net of income taxes			(367)	
Net income	$ 81,638	$ 29,528	$ 152,890	$ 33,714
Basic income (loss) per common share:				
Income from continuing operations	$ 0.53	$ 0.19	$ 0.99	$ 0.22
Loss from discontinued operations, net of income taxes	$ 0.00	$ 0.00	$ 0.00	$ 0.00
Net income	$ 0.53	$ 0.19	$ 0.99	$ 0.22

Diluted income (loss) per common share:				
Income from continuing operations	$ 0.52	$ 0.19	$ 0.98	$ 0.22
Loss from discontinued operations, net of income taxes	$ 0.00	$ 0.00	$ 0.00	$ 0.00
Net income	$ 0.52	$ 0.19	$ 0.98	$ 0.22
Weighted average number of common shares outstanding:				
Basic	153,556	152,650	153,340	152,554
Diluted	155,581	152,871	155,252	152,852
Cash dividends per common share	$ 0.05	$ 0.05	$ 0.10	$ 0.10

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY

(unaudited, in thousands)

	Common Stock				Accumulated		
	Number of Shares	Amount	Additional Paid-in Capital	Retained Earnings	Other Comprehensive Income	Treasury Stock	Total
Balance, December 31, 2010	181,538	$ 1,815	$ 796,641	$ 1,987,999	$ 21,597	$ (620,445)	$ 2,187,607
Comprehensive income:							
Net income				152,890			152,890
Foreign currency translation adjustment					2,160		2,160
Total comprehensive income				152,890	2,160		155,050
Issuance of restricted stock	767	8	(8)				
Vesting of stock unit awards	10						
Forfeitures of restricted stock	(19)						
Exercise of stock options	748	7	13,001				13,008
Stock-based compensation			9,850				9,850
Tax benefit related to stock-based compensation			5,241				5,241
Payment of cash dividends				(15,480)			(15,480)
Purchases of treasury stock						(4,216)	(4,216)
Balance, June 30, 2011	183,044	$ 1,830	$ 824,725	$ 2,125,409	$ 23,757	$ (624,661)	$ 2,351,060

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY

(unaudited, in thousands)

	Common Stock		Additional		Accumulated		
	Number of Shares	Amount	Paid-in Capital	Retained Earnings	Other Comprehensive Income	Treasury Stock	Total
Balance, December 31, 2009	180,829	$ 1,808	$ 781,635	$ 1,901,853	$ 14,996	$ (618,592)	$ 2,081,700
Comprehensive income:							
Net income				33,714			33,714
Foreign currency translation adjustment, net of tax of $2,814					3,031		3,031
Total comprehensive income				33,714	3,031		36,745
Issuance of restricted stock	646	7	(7)				
Vesting of stock unit awards	7						
Forfeitures of restricted stock	(53)						
Exercise of stock options	34		290				290
Stock-based compensation			7,987				7,987
Tax expense related to stock-based compensation			(1,484)				(1,484)
Payment of cash dividends				(15,383)			(15,383)
Purchases of treasury stock						(1,433)	(1,433)
Balance, June 30, 2010	181,463	$ 1,815	$ 788,421	$ 1,920,184	$ 18,027	$ (620,025)	$ 2,108,422

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited, in thousands)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash flows from operating activities:		
Net income	$ 152,890	$ 33,714
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and impairment	198,964	154,499
Provision for bad debts		(1,000)
Dry holes and abandonments	150	486
Deferred income tax expense	70,001	21,388
Stock-based compensation expense	9,850	7,987
Net gain on asset disposals	(2,621)	(21,690)
Tax expense related to stock-based compensation		(1,484)
Changes in operating assets and liabilities:		
Accounts receivable	(71,416)	(47,382)
Income taxes receivable/payable	73,749	113,690
Inventory and other assets	(13,719)	(13,283)
Accounts payable	10,649	18,441
Accrued expenses	11,863	16,338
Other liabilities	(4,748)	1,190
Net cash provided by (used in) operating activities of discontinued operations	(339)	10,687
Net cash provided by operating activities	435,273	293,581
Cash flows from investing activities:		
Purchases of property and equipment	(427,618)	(298,845)
Proceeds from disposal of assets	7,474	25,231
Net cash provided by investing activities of discontinued operations	25,500	42,646
Net cash used in investing activities	(394,644)	(230,968)
Cash flows from financing activities:		
Purchases of treasury stock	(4,216)	(1,433)
Dividends paid	(15,480)	(15,383)
Repayment of long-term debt	(2,500)	
Tax benefit related to stock-based compensation	5,241	
Proceeds from exercise of stock options	13,008	290
Net cash used in financing activities	(3,947)	(16,526)
Effect of foreign exchange rate changes on cash	290	15
Net increase in cash and cash equivalents	36,972	46,102
Cash and cash equivalents at beginning of period	27,612	49,877
Cash and cash equivalents at end of period	$ 64,584	$ 95,979
Supplemental disclosure of cash flow information:		
Net cash (paid) received during the period for:		

Interest expense, net of capitalized interest of $4,468 in 2011 and $0 in 2010	$ (6,207)	$ (1,733)
Income taxes	$ 61,351	$ 115,727
Supplemental investing and financing information:		
Net increase in payables for purchases of property and equipment	$ 57,808	$ 71,259
Net increase in deposits on equipment purchases	$ (15,219)	$ (32,026)

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Consolidation and Presentation

The unaudited interim 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 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 have been included. The Unaudited Consolidated Balance Sheet as of December 31, 2010, 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 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, 2010. The results of operations for the three and six months ended June 30, 2011 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 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 income from continuing operations per share, loss from discontinued operations per share and net income per share for the three and six months ended June 30, 2011 and 2010 as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding, as their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
BASIC EPS:				
Income from continuing operations	$ 81,638	$ 29,528	$ 153,257	$ 33,714
Adjust for income attributed to holders of non-vested restricted stock	(648)	(232)	(1,145)	(254)
Income from continuing operations attributed to common stockholders	$ 80,990	$ 29,296	$ 152,112	$ 33,460
Loss from discontinued operations, net	$	$	$ (367)	$
Adjust for loss attributed to holders of non-vested restricted stock			3	
Loss from discontinued operations attributed to common stockholders	$	$	$ (364)	$
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	153,556	152,650	153,340	152,554
Basic income from continuing operations per common share	$ 0.53	$ 0.19	$ 0.99	$ 0.22
Basic loss from discontinued operations per common share	$ 0.00	$ 0.00	$ 0.00	$ 0.00
Basic net income per common share	$ 0.53	$ 0.19	$ 0.99	$ 0.22
DILUTED EPS:				
Income from continuing operations attributed to common stockholders	$ 80,990	$ 29,296	$ 152,112	$ 33,460
Add incremental earnings related to potential common shares	8			
Adjusted income from continuing operations attributed to common stockholders	$ 80,998	$ 29,296	$ 152,112	$ 33,460
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	153,556	152,650	153,340	152,554
Add dilutive effect of potential common shares	2,025	221	1,912	298
Weighted average number of diluted common shares outstanding	155,581	152,871	155,252	152,852
Diluted income from continuing operations per common share	$ 0.52	$ 0.19	$ 0.98	$ 0.22
Diluted loss from discontinued operations per common share	$ 0.00	$ 0.00	$ 0.00	$ 0.00
Diluted net income per common share	$ 0.52	$ 0.19	$ 0.98	$ 0.22
Potentially dilutive securities excluded as anti-dilutive	380	6,907	1,796	6,907

2. Discontinued Operations

On January 27, 2011, the stock of the Company s electric wireline subsidiary, Universal Wireline, Inc., was sold in a cash transaction for $25.5 million. Except for inventory, the working capital of Universal Wireline, Inc. was excluded from the sale and retained by a subsidiary of the Company. Universal Wireline, Inc. was formed in 2010 to acquire the electric wireline business of Key Energy Services, Inc., as discussed in Note 3. The results of operations of this business have been presented as results of discontinued operations in these consolidated financial statements. As of December 31, 2010, the assets to be disposed of were classified as held for sale and are presented separately within current assets under the caption Assets held for sale in the consolidated balance sheet. Upon being classified as held for sale, the assets to be disposed of were recorded at fair value less estimated costs to sell resulting in a charge of $2.2 million. Due to the fact that the carrying value of the assets had been adjusted to net realizable value during 2010, no significant additional gain or loss was recognized in connection with the sale in 2011.

On January 20, 2010, the Company exited the drilling and completion fluids business, which had previously been presented as one of the Company s reportable operating segments. On that date, the Company s wholly owned subsidiary, Ambar Lone Star Fluids Services LLC, completed the sale of substantially all of its assets, excluding billed accounts receivable. The sales price was approximately $42.6 million. Upon the Company s exit from the drilling and completion fluids business, the Company classified its drilling and completion fluids operating segment as a discontinued operation and an impairment loss was recognized in 2009 to reduce the carrying value of the assets to be disposed of to fair value less estimated costs to sell and no significant gain or loss was recognized in connection with the sale in 2010. The results of operations of this business have been reclassified and presented as results of discontinued operations for all periods presented in these consolidated financial statements.

Summarized operating results from discontinued operations for the three and six months ended June 30, 2011, and 2010 are shown below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Electric wireline revenues	$	$	$ 1,104	$
Drilling and completion fluids revenues				3,737
Operating revenues from discontinued operations	$	$	$ 1,104	$ 3,737
Loss before income taxes	$	$	$ (576)	$
Income tax benefit			209	
Loss from discontinued operations, net of income tax	$	$	$ (367)	$

3. Acquisitions

On October 1, 2010, two subsidiaries of the Company, Universal Pressure Pumping, Inc. and Universal Wireline, Inc., completed the acquisition of certain assets from Key Energy Pressure Pumping Services, LLC and Key Electric Wireline Services, LLC relating to the businesses of providing pressure pumping services and electric wireline services to participants in the oil and natural gas industry. This acquisition expanded the Company s pressure pumping operations to additional markets primarily in Texas. As discussed in Note 2, the electric wireline business was classified as held for sale at December 31, 2010 and was subsequently sold on January 27, 2011. Results of operations of the acquired pressure pumping business are included in the Company s consolidated results of operations from the date of acquisition. The consolidated statement of operations includes revenues from the acquired pressure pumping business of $99.6 million and $196 million for the three and six months ended June 30, 2011, respectively. The consolidated statement of operations includes income from operations from the acquired pressure pumping business of $22.3 million and $49.9 million for the three and six months ended June 30, 2011, respectively.

4. 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 both cash-settled and share-settled performance unit awards. Cash-settled performance unit awards are accounted for as liability 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 in the three and six month periods ended June 30, 2011 and 2010 follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Volatility	45.82%	45.92%	45.97%	45.98%
Expected term (in years)	5.00	5.00	5.00	5.00
Dividend yield	0.64%	1.35%	0.67%	1.35%
Risk-free interest rate	2.38%	2.46%	2.34%	2.47%

Stock option activity from January 1, 2011 to June 30, 2011 follows:

	Underlying Shares	Weighted Average Exercise Price
Outstanding at January 1, 2011	7,710,102	$ 19.58
Granted	419,500	$ 30.28
Exercised	(748,002)	$ 17.39
Outstanding at June 30, 2011	7,381,600	$ 20.41
Exercisable at June 30, 2011	6,027,308	$ 20.68

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. For restricted stock awards made prior to 2008, the Company uses the graded-vesting attribution method to recognize periodic compensation cost over the vesting period. For restricted stock awards made in 2008 and thereafter, the Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity from January 1, 2011 to June 30, 2011 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock outstanding at January 1, 2011	1,114,051	$ 16.05
Granted	767,300	$ 30.71
Vested	(492,714)	$ 18.20
Forfeited	(19,282)	$ 19.62
Non-vested restricted stock outstanding at June 30, 2011	1,369,355	$ 23.44

Restricted Stock Units. For all restricted stock unit awards made to date, shares of common stock will not be 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 non-vested restricted stock units.

Restricted stock unit activity from January 1, 2011 to June 30, 2011 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock units outstanding at January 1, 2011	17,834	$ 19.73
Granted	10,000	$ 30.63
Vested	(10,333)	$ 23.94
Forfeited		$
Non-vested restricted stock units outstanding at June 30, 2011	17,501	$ 23.47

Performance Unit Awards. In 2009, the Company granted cash-settled performance unit awards to certain executive officers (the 2009 Performance Units). The 2009 Performance Units provide for those executive officers to receive a cash payment upon the achievement of certain performance goals established by the Company during a specified period. The performance period for the 2009 Performance Units is the period from April 1, 2009 through March 31, 2012, but can extend through March 31, 2014 in certain circumstances. The performance goals for the 2009 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 of the Board of Directors. These goals are considered to be market conditions under the relevant accounting standards and the market conditions are factored into the determination of the fair value of the performance units. Generally, the recipients will receive a base payment if the Company s total shareholder return is positive and, when compared to the peer group, is at or above the 25^{th} percentile but less than the 50^{th} percentile, two times the base if at or above the 50^{th} percentile but less than the 75^{th} percentile, and four times the base if at the 75^{th} percentile or higher. The total base amount with respect to the 2009 Performance Units is approximately $1.7 million. Because the 2009 Performance Units are to be settled in cash at the end of the performance period, they are accounted for as liability awards and the Company s pro-rated obligation is measured at estimated fair value at the end of each reporting period using a Monte Carlo simulation model. As of June 30, 2011 this pro-rated obligation was approximately $4.6 million and is included in the caption accrued expenses in the liabilities section of the consolidated balance sheet. Compensation expense associated with the 2009 Performance Units was approximately $1.0 million and $2.2 million for the three and six month periods ended June 30, 2011, respectively. Compensation expense associated with the 2009 Performance Units was approximately $361,000 and $57,000 for the three and six month periods ended June 30, 2010, respectively.

In 2010 and 2011, the Company granted stock-settled performance unit awards to certain executive officers (the 2010 Performance Units and the 2011 Performance Units , respectively). The 2010 Performance Units and the 2011 Performance Units provide for those executive officers to receive a grant of shares of stock upon the achievement of certain performance goals established by the Company during a specified period. The performance period for the 2010 Performance Units is the period from April 1, 2010 through March 31, 2013, but can extend through March 31, 2015 in certain circumstances. The performance period for the 2011 Performance Units is the period from April 1, 2011 through March 31, 2014, but can extend through March 31, 2016 in certain circumstances. The performance goals for the 2010 Performance Units and the 2011 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 of the Board of Directors. These goals are considered to be market conditions under the relevant accounting standards and the market conditions are factored into the determination of the fair value of the respective performance units. Generally, the recipients will receive a base number of shares if the Company s total shareholder return is positive and, when compared to the peer group, is at or above the 25th percentile but less than the 50th percentile, two times the base if at or above the 50th percentile but less than the 75th percentile, and four times the base if at the 75th percentile or higher. The grant of shares when achievement is between the 25th and 75th percentile will be determined on a pro-rata basis. The total base number of shares with respect to the 2010 Performance Units is 89,375 shares and the total base number of shares with respect to the 2011 Performance Units is 72,188 shares. Because the 2010 and 2011 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 2010 Performance Units as of the date of grant was approximately $3.1 million and the fair value of the 2011 Performance Units as of the date of grant was approximately $5.6 million. This fair value is recognized on a straight-line basis over the performance period. Compensation expense associated with the 2010 Performance Units was approximately $260,000 and $520,000 for the three and six month periods ended June 30, 2011, respectively. Compensation expense associated with the 2011 Performance Units was approximately $464,000 for the three and six month periods ended June 30, 2011.

5. Property and Equipment

Property and equipment consisted of the following at June 30, 2011 and December 31, 2010 (in thousands):

	June 30, 2011	December 31, 2010
Equipment	$ 4,336,763	$ 3,972,891
Oil and natural gas properties	118,506	110,749
Buildings	61,768	61,425
Land	11,103	11,074
	4,528,140	4,156,139
Less accumulated depreciation and depletion	(1,637,472)	(1,535,239)
Property and equipment, net	$ 2,890,668	$ 2,620,900

6. 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 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. As discussed in Note 2, in January 2010 the Company exited the drilling and completion fluids business which previously was reported as a business segment. Operating results for that business are presented as discontinued operations in the consolidated statements of operations. Also included in discontinued operations are the operating results for an electric wireline business that was acquired on October 1, 2010 and sold in January 2011. Separate financial data for each of our business segments is provided in the table below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues:				
Contract drilling	$ 387,622	$ 240,894	$ 765,647	$ 452,371
Pressure pumping	200,131	59,364	379,790	113,115
Oil and natural gas	13,454	7,662	23,841	14,764
Total segment revenues	601,207	307,920	1,169,278	580,250
Elimination of intercompany revenues (a)	(1,143)	(928)	(1,810)	(1,660)
Total revenues	$ 600,064	$ 306,992	$ 1,167,468	$ 578,590
Income before income taxes:				
Contract drilling	$ 85,135	$ 22,099	$ 165,654	$ 30,800
Pressure pumping	50,340	6,706	91,718	11,183
Oil and natural gas	7,129	2,927	11,947	5,744
	142,604	31,732	269,319	47,727
Corporate and other	(11,761)	(7,914)	(22,533)	(15,829)
Net gain on asset disposals (b)	1,017	21,939	2,621	21,690
Interest income	45	1,380	88	1,567
Interest expense	(3,514)	(1,383)	(7,403)	(2,784)
Other	78	174	197	249
Income from continuing operations before income taxes	$ 128,469	$ 45,928	$ 242,289	$ 52,620

	June 30, 2011	December 31, 2010
Identifiable assets:		
Contract drilling	$ 2,950,576	$ 2,678,250
Pressure pumping	638,255	533,597
Oil and natural gas	40,751	36,508
Corporate and other (c)	148,007	174,676
Total assets	$ 3,777,589	$ 3,423,031

(a)

Consists of contract drilling intercompany revenues for drilling 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 at December 31, 2010 primarily include assets held for sale as well as cash on hand, income taxes receivable and certain deferred tax assets. Corporate and other assets at June 30, 2011 primarily include cash on hand and certain deferred tax assets.

7. Goodwill and Intangible Assets

Goodwill Goodwill by operating segment as of June 30, 2011 and changes for the six months then ended are as follows (in thousands):

	January 1, Balance	Changes to Goodwill	June 30, Balance
Contract Drilling:			
Goodwill	$ 86,234	$	$ 86,234
Accumulated impairment losses			
Net goodwill in contract drilling segment	86,234		86,234
Pressure Pumping:			
Goodwill	67,575		67,575
Accumulated impairment losses			
Net goodwill in pressure pumping segment	67,575		67,575
Total goodwill	$ 153,809	$	$ 153,809

Goodwill by operating segment as of June 30, 2010 and changes for the six months then ended are as follows (in thousands):

	January 1, Balance	Changes to Goodwill	June 30, Balance
Contract Drilling:			
Goodwill	$ 86,234	$	$ 86,234
Accumulated impairment losses			
Net goodwill in contract drilling segment	86,234		86,234
Total goodwill	$ 86,234	$	$ 86,234

Goodwill of $67.6 million was recorded in the fourth quarter of 2010 as a result of the Company s acquisition of the pressure pumping business of Key Energy Services, Inc. on October 1, 2010. Approximately $53.2 million of this goodwill is expected to be deductible for tax purposes.

Goodwill is evaluated at least annually on December 31 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. In the event that market conditions weaken in the future, the Company may be required to record impairments of goodwill in its contract drilling or pressure pumping reporting units, and such impairment could be material.

Intangible Assets Intangible assets of $26.9 million were recorded in the pressure pumping operating segment in connection with the Company s acquisition of a pressure pumping business on October 1, 2010. As a result of the purchase price allocation, the Company recorded intangible assets related to a non-compete agreement and the customer relationships acquired. These intangible assets were recorded at fair value on the date of acquisition.

The non-compete agreement has a term of three years from October 1, 2010. The value of this agreement was estimated using a with and without scenario where cash flows were projected through the term of the agreement assuming the agreement is in place and compared to cash flows assuming the non-compete agreement was not in place. The intangible asset associated with the non-compete agreement is being amortized on a straight-line basis over the three-year term of the agreement. Amortization expense of $117,000 and $233,000 was recorded in the three and six months ended June 30, 2011, respectively, associated with the non-compete agreement.

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 $910,000 and $1.8 million was recorded in the three and six months ended June 30, 2011, respectively, associated with customer relationships.

The following table sets forth the activity with respect to intangible assets for the six months ended June 30, 2011 (in thousands):

	January 1, Balance	Amortization	June 30, Balance
Non-compete agreement	$ 1,400	$	$ 1,400
Accumulated amortization	(116)	(233)	(349)
Net non-compete agreement	1,284	(233)	1,051
Customer relationships	25,500		25,500
Accumulated amortization	(910)	(1,822)	(2,732)
Net customer relationships	24,590	(1,822)	22,768
Total intangible assets, net (excluding goodwill)	$ 25,874	$ (2,055)	$ 23,819

8. Accrued Expenses

Accrued expenses consisted of the following at June 30, 2011 and December 31, 2010 (in thousands):

	June 30, 2011	December 31, 2010
Salaries, wages, payroll taxes and benefits	$ 40,872	$ 39,866
Workers compensation liability	63,174	63,011
Sales, use and other taxes	13,542	6,682
Insurance, other than workers compensation	7,570	12,648
Accrued interest payable	4,866	4,879
Deferred revenue current	7,229	10,220
2009 Performance Unit Awards	4,563	
Other	16,442	10,009
	$ 158,258	$ 147,315

Deferred revenue was recorded in the fourth quarter of 2010 in the purchase price allocation associated with the Company s acquisition of a pressure pumping business as discussed in Note 3. The deferred revenue relates to out-of-market pricing agreements that were in place at the acquired business at the time of the acquisition. The deferred revenue is recognized as pressure pumping revenue over the remaining term of the pricing agreements. Deferred revenue of approximately $1.8 million and $4.7 million was recognized in the three and six months ended June 30, 2011, respectively, related to these pricing agreements.

9. 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 consolidated balance sheet. The following table describes the changes to the Company s asset retirement obligations during the six months ended June 30, 2011 and 2010 (in thousands):

	Six Months Ended June 30,	
	2011	2010
Balance at beginning of year	$ 3,063	$ 2,955
Liabilities incurred	152	142
Liabilities settled	(80)	(184)
Accretion expense	70	55
Revision in estimated costs of plugging oil and natural gas wells	(2)	
Asset retirement obligation at end of period	$ 3,203	$ 2,968

10. Long Term Debt

On August 19, 2010, the Company entered into a Credit Agreement (the 2010 Credit Agreement) among the Company, as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other letter of credit issuer and lender parties thereto. The 2010 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 $400 million and contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million. Subject to customary conditions, the Company may request that the lenders aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $500 million. The maturity date for the revolving facility is August 19, 2013.

The term loan facility provided for a loan of $100 million which was funded on August 19, 2010. The term loan facility is payable in quarterly principal installments commencing November 19, 2010, 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 next subsequent three quarterly installments, with the remainder becoming due at maturity. The maturity date for the term loan facility is August 19, 2014.

Loans under the 2010 Credit Agreement bear interest by reference, at the Company s election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 2.75% to 3.75% and the applicable margin on base rate loans varies from 1.75% to 2.75%, in each case determined based upon the Company s debt to capitalization ratio. As of June 30, 2011, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. 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 payable to the lenders for the unused portion of the revolving credit facility varies from 0.50% to 0.75% based upon the Company s debt to capitalization ratio and was 0.50% as of June 30, 2011.

Each domestic subsidiary of the Company other than any immaterial subsidiary has unconditionally guaranteed all existing and future indebtedness and liabilities of the Company and the other guarantors arising under the 2010 Credit Agreement and other loan documents. 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 affiliate of a lender under the 2010 Credit Agreement.

The 2010 Credit Agreement contains customary representations, warranties, indemnities and affirmative and negative covenants. The 2010 Credit Agreement also requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 45% at any time. The 2010 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 2010 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 does not expect that the restrictions and covenants will impact its ability to operate or react to opportunities that might arise.

As of June 30, 2011, the Company had approximately $96.3 million principal amount outstanding under the term loan facility at an interest rate of 3.125% and no borrowings outstanding under the revolving credit facility. The carrying value of the balance outstanding under the term loan facility approximates fair value. The Company had $40.6 million in letters of credit outstanding at June 30, 2011 and, as a result, had available borrowing capacity under the revolving credit facility of approximately $359 million at that date.

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 Notes) in a private placement. A portion of the proceeds from the Notes was used to repay a $200 million borrowing on the Company s revolving credit facility, which had been drawn to fund a portion of the acquisition that closed on October 1, 2010 as discussed in Note 3. The carrying value of the Notes at June 30, 2011 approximated fair value. The Notes are senior unsecured obligations of the Company which rank equally in right of payment with all other unsubordinated indebtedness of the Company. The Notes are guaranteed on a senior unsecured basis by each of the existing domestic subsidiaries of the Company other than immaterial subsidiaries.

The Notes bear interest at a rate of 4.97% per annum and were priced at 100% of the principal amount of the Notes. The Company will pay interest on the Notes on April 5 and October 5 of each year commencing on April 5, 2011. The Notes will mature on October 5, 2020. The 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 agreement. 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 note purchase agreement requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 50% at any time. The note purchase 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 2.50 to 1.00. The note purchase agreement generally defines the interest coverage ratio as the ratio for the four prior quarters of EBITDA to interest charges for that same period. The Company does not expect that the restrictions and covenants will impair its ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreement 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 occurs and is continuing, then holders of a majority in principal amount of the 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 to be immediately due and payable.

The Company incurred approximately $10.8 million in debt issuance costs in connection with the 2010 Credit Agreement and the Senior Notes discussed above. These costs were deferred and will be recognized as interest expense over the term of the underlying debt. Interest expense related to the amortization of debt issuance costs for the 2010 Credit Agreement and the Senior Notes was approximately $604,000 and $1.2 million for the three and six months ended June 30, 2011, respectively.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of June 30, 2011 (in thousands):

Year ending December 31,	
2011	$ 3,750
2012	10,000
2013	12,500
2014	70,000
2015	
Thereafter	300,000
Total	$ 396,250

11. Commitments, Contingencies and Other Matters

As of June 30, 2011, the Company maintained letters of credit in the aggregate amount of $40.6 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 June 30, 2011, no amounts had been drawn under the letters of credit.

As of June 30, 2011, the Company had commitments to purchase approximately $366 million of major equipment.

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.

12. Stockholders Equity

Cash Dividends The Company paid cash dividends during the six months ended June 30, 2010 and 2011 as follows:

2010:	**Per Share**	**Total**
		(in thousands)
Paid on March 30, 2010	$ 0.05	$ 7,677
Paid on June 30, 2010	0.05	7,706
Total cash dividends	$ 0.10	$ 15,383

2011:	**Per Share**	**Total**
		(in thousands)
Paid on March 30, 2011	$ 0.05	$ 7,708
Paid on June 30, 2011	0.05	7,772
Total cash dividends	$ 0.10	$ 15,480

On July 27, 2011, the Company s Board of Directors approved a cash dividend on its common stock in the amount of $0.05 per share to be paid on September 30, 2011 to holders of record as of September 15, 2011. 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 the Company s credit facilities and other factors.

On August 1, 2007, the Company s Board of Directors approved a stock buyback program authorizing purchases of up to $250 million of the Company s common stock in open market or privately negotiated transactions. During the six months ended June 30, 2011, 8,025 shares were purchased under the program at a cost of approximately $242,000. As of June 30, 2011, the Company is authorized to purchase approximately $113 million of the Company s outstanding common stock under the program. Shares purchased under the program are accounted for as treasury stock.

The Company purchased 130,768 shares of treasury stock from employees during the six months ended June 30, 2011. These shares were purchased at fair market value upon the vesting of restricted stock to provide the employees with the funds necessary to satisfy payroll tax withholding obligations. The total purchase price for these shares was approximately $4.0 million. These purchases were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan and not pursuant to the stock buyback program.

13. Income Taxes

On January 1, 2010, the Company converted its Canadian operations from a Canadian branch to a controlled foreign corporation for Federal income tax purposes. Because the statutory tax rates in Canada are lower than those in the United States, this transaction triggered a $5.1 million reduction in the Company s deferred tax liabilities, which is being amortized as a reduction to deferred income tax expense over the weighted average remaining useful life of the Canadian assets.

As a result of the above conversion, the Company s Canadian assets are no longer subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, the Company has elected to permanently reinvest these unremitted earnings in Canada, and it intends to do so for the foreseeable future. As a result, no deferred United States Federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $13.5 million as of June 30, 2011.

14. Recently Issued Accounting Standards

In June 2011, the FASB issued an accounting standard update that requires that all non-owner changes in stockholders equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income, and the total of comprehensive income. Historically, these components of other comprehensive income and total comprehensive income have been presented in the statement of changes in stockholders equity by many companies, including us. This requirement is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and will be effective for the Company in the quarter ending March 31, 2012. The adoption of this update will not impact the Company s consolidated financial position, results of operations or cash flows; however it will result in the addition of a new consolidated statement of comprehensive income to the Company s consolidated financial statements.

In May 2011, the FASB issued an accounting standard update to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with United States GAAP and International Financial Reporting Standards. The amendments in this update do not require additional fair value measurements, but provide additional guidance as to measuring fair value as well as certain additional disclosure requirements. The requirements in this update are effective during interim and annual periods beginning after December 15, 2011 and will be effective for the Company in the quarter ending March 31, 2012. The adoption of this update will not have a material impact on the Company s disclosures included in its consolidated financial statements.

In October 2009, the FASB issued a new accounting standard that addresses the accounting for multiple-deliverable revenue arrangements to enable vendors to account for deliverables separately rather than as a combined unit. This new standard addresses how to separate deliverables and how to measure and allocate arrangement consideration to one or more units of accounting. Existing accounting standards require a vendor to use objective and reliable evidence of fair value for the undelivered items or the residual method to separate deliverables in a multiple-deliverable arrangement. Under the new standard, it is expected that multiple-deliverable arrangements will be separated in more circumstances than under current requirements. The new standard establishes a hierarchy for determining the selling price of a deliverable for purposes of allocating revenue to multiple deliverables. The selling price used will be based on vendor-specific objective evidence if available, third-party evidence if vendor-specific objective evidence is not available, or estimated selling price if neither vendor-specific objective evidence nor third-party evidence is available. The new standard must be prospectively applied to all revenue arrangements entered into in fiscal years beginning on or after June 15, 2010 and became effective for the Company on January 1, 2011. The adoption of this standard did not have a material impact on the Company s consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting standard update that addresses the disclosure of supplementary pro forma information for business combinations. This update clarifies that when public entities are required to disclose pro forma information for business combinations that occurred in the current reporting period, the pro forma information should be presented as if the business combination occurred as of the beginning of the previous fiscal year when comparative financial statements are presented. This update is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Early adoption is permitted. The Company elected to early adopt this update, and this early adoption did not have an impact on the disclosures included in 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), and 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; financing of operations; continued volatility of 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; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historic or current facts and often use words such as believes, budgeted, continue, expects, estimates, project, will, may, plans, intends, strategy, or anticipates, or the negative thereof and other words and expressions of similar meaning. The forward-lookin 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, deterioration of global economic conditions, declines in oil and natural gas prices that could adversely affect demand for our services and their associated effect on day rates, utilization, margins and planned capital expenditures, excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction, adverse industry conditions, adverse credit and equity market conditions, difficulty in integrating acquisitions, shortages of equipment and materials, governmental regulation and ability to retain management and field personnel. Refer to Risk Factors contained in Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2010 for a more complete discussion of these and other 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.

ITEM 2. ***Management s Discussion and Analysis of 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 the aforementioned services, we also invest, on a working interest basis, in oil and natural gas properties. Prior to the sale of substantially all of the assets of our drilling and completion fluids business in January 2010, we provided drilling fluids, completion fluids and related services to oil and natural gas operators. Due to our exit from the drilling and completion fluids business in January 2010, we have presented the results of that operating segment as discontinued operations in this Report. We acquired an electric wireline business on October 1, 2010 and sold the business on January 27, 2011. Due to our exit from the electric wireline business, we have presented the results of that business as discontinued operations in this Report. For the three and six months ended June 30, 2011 and 2010, our operating revenues from continuing operations consisted of the following (dollars in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2011		2010		2011		2010	
Contract drilling	$ 386,479	65%	$ 239,966	79%	$ 763,837	65%	$ 450,711	77%
Pressure pumping	200,131	33	59,364	19	379,790	33	113,115	20
Oil and natural gas	13,454	2	7,662	2	23,841	2	14,764	3
	$ 600,064	100%	$ 306,992	100%	$ 1,167,468	100%	$ 578,590	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 second quarter of 2011, our average number of rigs operating was 202 compared to 156 in the second quarter of 2010. Our average revenue per operating day was $21,000 in the second quarter of 2011 compared to $16,920 in the second quarter of 2010. Additionally, our pressure pumping segment experienced an increase in large multi-stage fracturing jobs in 2011 compared to 2010. This increase includes the contribution of a pressure pumping business we acquired on October 1, 2010, which significantly expanded our pressure pumping operations into new markets. We had

consolidated net income of $81.6 million for the second quarter of 2011 compared to consolidated net income of $29.5 million for the second quarter of 2010. The increase in consolidated net income was primarily due to our contract drilling segment experiencing an increase in the average number of rigs operating and an increase in the average revenue per operating day as well as greater activity, pricing and size of our pressure pumping business.

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. After reaching a peak in June 2008, there was a significant extended decline in oil and natural gas prices and a substantial deterioration in the global economic environment. As part of this deterioration, there was substantial uncertainty in the capital markets and access to financing was reduced. Due to these conditions, our customers reduced or curtailed their drilling programs, which resulted in a decrease in demand for our services, as evidenced by the decline in our monthly average of rigs operating from a high of 283 in October 2008 to a low of 60 in June 2009. Our monthly average number of rigs operating has subsequently increased from the mid-year low of 60 in 2009 to 205 in June 2011 and our profitability improved.

In 2008 and 2009, the decline in commodity prices and deterioration in the global economy resulted in certain of our customers experiencing an inability to pay suppliers, including us. We are also highly impacted by competition, the availability of excess equipment, labor issues 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, 2010.

We believe that our liquidity as of June 30, 2011, which includes approximately $233 million in working capital and approximately $359 million available under our $400 million revolving credit facility, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to build new equipment, make improvements to 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 or additional debt or 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 June 30, 2011, we maintained letters of credit in the aggregate amount of $40.6 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 June 30, 2011, no amounts had been drawn under the letters of credit.

As of June 30, 2011, we had commitments to purchase approximately $366 million of major equipment.

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 Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia, Ohio and western Canada. As of June 30, 2011, we had approximately 360 marketable land-based drilling rigs. We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian Basin. Pressure pumping services are primarily well stimulation and cementing for completion of new wells and remedial work on existing wells. We also invest, on a working interest basis, in oil and natural gas properties.

The North American land drilling industry has experienced periods of downturn in demand over the last decade. During these periods, there have been substantially more drilling rigs available than necessary to meet demand. As a result, drilling contractors have had difficulty sustaining profit margins and, at times, have sustained losses during the downturn periods.

In addition, unconventional resource plays have substantially increased recently and some drilling rigs are not capable of drilling these wells efficiently. Accordingly, the utilization of some older technology drilling rigs may be hampered by their lack of capability to successfully 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 drilling rigs.

Construction of new drilling rigs increased significantly during the last ten years. The addition of new drilling rigs to the market has, at times, resulted in excess capacity. Similarly, the substantial recent increase in unconventional resource plays has led to higher demand for pressure pumping services. As a result, we believe there has been, and we expect there to continue to be, a significant increase in the construction of new pressure pumping equipment. The addition of new pressure pumping equipment, as well as any general decline in demand for pressure pumping services, could result in there being substantially more pressure pumping equipment available than necessary to meet demand. If this were to occur, providers of pressure pumping services will 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.

Critical Accounting Policies

In addition to established accounting policies, our 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, 2010.

Liquidity and Capital Resources

As of June 30, 2011, we had working capital of $233 million, including cash and cash equivalents of $64.6 million compared to working capital of $241 million and cash and cash equivalents of $27.6 million at December 31, 2010.

During the six months ended June 30, 2011, our sources of cash flow included:

- $435 million from operating activities,
- $25.5 million in proceeds from the disposal of our electric wireline business,
- $18.2 million from the exercise of stock options and related tax benefits associated with stock-based compensation, and
- $7.5 million in proceeds from the disposal of property and equipment.

During the six months ended June 30, 2011, we used $15.5 million to pay dividends on our common stock, $4.2 million to repurchase shares of our common stock, $2.5 million to repay long-term debt and $428 million:

- to build new drilling rigs and pressure pumping equipment,
- to make capital expenditures for the betterment and refurbishment of our 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 working interest basis.

We paid cash dividends during the six months ended June 30, 2011 as follows:

	Per Share		Total (in thousands)	
Paid on March 30, 2011	$	0.05	$	7,708
Paid on June 30, 2011	$	0.05	$	7,772
Total cash dividends	$	0.10	$	15,480

On July 27, 2011, our Board of Directors approved a cash dividend on our common stock in the amount of $0.05 per share to be paid on September 30, 2011 to holders of record as of September 15, 2011. 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 factors.

On August 1, 2007, our Board of Directors approved a stock buyback program, authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions. During the six months ended June 30, 2011, we purchased 8,025 shares of our common stock under this program at a cost of approximately $242,000. As of June 30, 2011, we are authorized to purchase approximately $113 million of our outstanding common stock under this program.

On August 19, 2010, we entered into the 2010 Credit Agreement. The 2010 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 $400 million and contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million. Subject to customary conditions, we may request that the lenders aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $500 million. The maturity date for the revolving facility is August 19, 2013.

The term loan facility provided for a loan of $100 million which was funded on August 19, 2010. The term loan facility is payable in quarterly principal installments commencing November 19, 2010. 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 next subsequent three quarterly installments, with the remainder becoming due at maturity. The maturity date for the term loan facility is August 19, 2014.

Loans under the 2010 Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 2.75% to 3.75% and the applicable margin on base rate loans varies from 1.75% to 2.75%, in each case determined based upon our debt to capitalization ratio. As of June 30, 2011, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. 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 payable to the lenders for the unused portion of the revolving credit facility varies from 0.50% to 0.75% based upon our debt to capitalization ratio and was 0.50% as of June 30, 2011.

The 2010 Credit Agreement contains customary representations, warranties, indemnities and affirmative and negative covenants. The 2010 Credit Agreement also requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45% at any time. The 2010 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 2010 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 June 30, 2011. We do not expect that the restrictions and covenants will impair our ability to operate or react to opportunities that might arise.

As of June 30, 2011, we had $96.3 million outstanding under the term loan facility at an interest rate of 3.125% and no borrowings outstanding under the revolving credit facility. We had $40.6 million in letters of credit outstanding at March 31, 2011 and, as a result, we had available borrowing capacity under the revolving credit facility of approximately $359 million at that date.

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 Notes) in a private placement.

The Notes bear interest at a rate of 4.97% per annum. We pay interest on the Notes on April 5 and October 5 of each year commencing on April 5, 2011. The Notes will mature on October 5, 2020. The Notes are prepayable at the 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 agreement. 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 note purchase agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase 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 2.50 to 1.00. The note purchase agreement generally defines the interest coverage ratio as the ratio for the four prior quarters of EBITDA to interest charges for the same period.

Events of default under the note purchase agreement 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 occurs and is continuing, then holders of a majority in principal amount of the 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 to be immediately due and payable.

We believe that the current level of cash, short-term investments and borrowing capacity available under our revolving credit facility, together with cash expected to be generated from operating activities, should be sufficient to fund our current plans to build new equipment, make improvements to our existing equipment, service our debt and pay cash dividends.

From time to time, opportunities to expand our business, including acquisitions and the building of new equipment, are evaluated. The timing, size or success of any acquisition and the associated capital commitments are unpredictable. 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 generated from operations, borrowing capacity under our revolving credit facility or additional debt or 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 June 30, 2011 and 2010:

Contract Drilling	**2011**	**2010**	**% Change**
	(Dollars in thousands)		
Revenues	$ 386,479	$ 239,966	61.1%
Direct operating costs	$ 218,754	$ 149,303	46.5%
Selling, general and administrative	$ 1,308	$ 920	42.2%
Depreciation and impairment	$ 81,282	$ 67,644	20.2%
Operating income	$ 85,135	$ 22,099	285.2%
Operating days	18,406	14,186	29.7%
Average revenue per operating day	$ 21.00	$ 16.92	24.1%
Average direct operating costs per operating day	$ 11.88	$ 10.52	12.9%
Average rigs operating	202	156	29.5%
Capital expenditures	$ 196,726	$ 171,501	14.7%

Revenues and direct operating costs increased in 2011 compared to 2010 as a result of an increase in the number of operating days and increases in average revenue and direct operating costs per operating day. Average revenue per operating day increased in 2011 primarily due to increases in contractual dayrates. Average direct operating costs per operating day increased in 2011 due primarily to increases in labor costs and repairs and maintenance expense resulting from increased drilling activity. The increase in operating days was due to increased demand largely caused by higher prices for oil. Capital expenditures were incurred in 2011 and 2010 to build new drilling rigs, to modify and upgrade our 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. Depreciation expense increased as a result of capital expenditures.

Pressure Pumping	**2011**	**2010**	**% Change**
	(Dollars in thousands)		
Revenues	$ 200,131	$ 59,364	237.1%
Direct operating costs	$ 128,866	$ 41,965	207.1%
Selling, general and administrative	$ 4,456	$ 2,805	58.9%
Depreciation and amortization	$ 16,469	$ 7,888	108.8%
Operating income	$ 50,340	$ 6,706	650.7%
Fracturing jobs	349	361	(3.3)%
Other jobs	1,636	1,496	9.4%
Total jobs	1,985	1,857	6.9%
Average revenue per fracturing job	$ 484.21	$ 118.13	309.9%
Average revenue per other job	$ 19.03	$ 11.18	70.2%
Average revenue per total job	$ 100.82	$ 31.97	215.4%
Average direct operating costs per total job	$ 64.92	$ 22.60	187.3%
Capital expenditures	$ 41,435	$ 11,398	263.5%

Contributing to the increases in revenues, direct operating costs, selling, general and administrative expenses and depreciation and amortization was our acquisition of a pressure pumping business on October 1, 2010, which significantly expanded the size of our fleet of pressure pumping equipment and the markets in which we provide pressure pumping services. This acquisition was accounted for as a business combination and the results of operations of the acquired business are included in our pressure pumping segment results from the date of acquisition. The acquired business contributed revenue of $99.6 million and operating income of $22.3 million to our operating results during the three months ended June 30, 2011.

Our customers have increased their activities in the development of unconventional reservoirs resulting in an increase in larger multi-stage fracturing jobs associated therewith. We have added additional equipment through construction and acquisitions to meet this demand and expand our area of operations. As a result, we have experienced a significant increase in the number of these larger multi-stage fracturing jobs as a proportion of the total fracturing jobs we performed. Average revenue per fracturing job increased as a result of this increase in the number of larger multi-stage fracturing jobs in 2011 as compared to 2010, as well as increased pricing. Average revenue per other job increased as a result of increased pricing for the services provided and a change in job mix. Average direct operating costs per total job increased primarily as a result of the increase in the number of larger multi-stage fracturing jobs. Selling, general and administrative expenses increased in 2011 due to $1.6 million in expenses associated with the acquired business. Significant capital expenditures have been incurred in recent years to add capacity in our pressure pumping segment. Depreciation and amortization expense in 2011 includes $1.0 million in amortization of intangible assets. The remaining increase in depreciation in 2011 compared to 2010 was a result of our recent capital expenditures and our October 1, 2010 acquisition.

Oil and Natural Gas Production and Exploration		**2011**	**2010**	**% Change**
		(Dollars in thousands, except sales prices)		
Revenues	Oil	$ 12,000	$ 6,221	92.9%
Revenues	Natural gas and liquids	$ 1,454	$ 1,441	0.9%
Revenues	Total	$ 13,454	$ 7,662	75.6%
Direct operating costs		$ 2,103	$ 1,780	18.1%
Depletion and impairment		$ 4,222	$ 2,955	42.9%
Operating income		$ 7,129	$ 2,927	143.6%
Capital expenditures		$ 5,078	$ 5,493	(7.6)%

Oil revenues increased due to a higher average sales price and an increase in average daily production of oil. Average net daily oil production increased primarily due to the addition of new wells. Depletion and impairment expense in 2011 includes approximately $759,000 of oil and natural gas property impairments compared to approximately $416,000 of oil and natural gas property impairments in 2010. Depletion expense increased approximately $924,000 in 2011 compared to 2010 primarily due to increased oil production.

Corporate and Other	**2011**	**2010**	**% Change**
	(Dollars in thousands)		
Selling, general and administrative	$ 10,985	$ 8,618	27.5%
Depreciation	$ 776	$ 296	162.2%
Net gain on asset disposals	$ (1,017)	$ (21,939)	(95.4)%
Provision for bad debts	$	$ (1,000)	(100.0)%
Interest income	$ 45	$ 1,380	(96.7)%
Interest expense	$ 3,514	$ 1,383	154.1%
Other income	$ 78	$ 174	(55.2)%
Capital expenditures	$ 1,827	$ 1,515	20.6%

Selling, general and administrative expense increased in 2011 primarily as a result of increased personnel costs. Gains 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. The gain on asset disposals in 2010 includes a gain of $20.1 million related to the sale of certain rights to explore and develop zones deeper than the depths that we generally target for certain of the oil and natural gas properties in which we have working interests. The negative provision for bad debts in 2010 is the result of collections of certain accounts that had previously been reserved in addition to reductions in our reserve for specific accounts due to improved industry conditions. Interest income in 2010 includes the collection of interest on a customer account as well as interest received on prior overpayments of sales taxes in certain jurisdictions. Interest expense increased in 2011 due to interest charges on the 4.97% Senior Notes that were issued in October 2010 and the term loan that was entered into in August 2010.

The following tables summarize operations by business segment for the six months ended June 30, 2011 and 2010:

Contract Drilling	**2011**	**2010**	**% Change**
	(Dollars in thousands)		
Revenues	$ 763,837	$ 450,711	69.5%
Direct operating costs	$ 437,453	$ 284,449	53.8%
Selling, general and administrative	$ 2,593	$ 2,152	20.5%
Depreciation and impairment	$ 158,137	$ 133,310	18.6%
Operating income	$ 165,654	$ 30,800	437.8%
Operating days	37,052	27,007	37.2%
Average revenue per operating day	$ 20.62	$ 16.69	23.5%
Average direct operating costs per operating day	$ 11.81	$ 10.53	12.2%
Average rigs operating	205	149	37.6%
Capital expenditures	$ 331,975	$ 263,475	26.0%

Revenues and direct operating costs increased in 2011 compared to 2010 as a result of an increase in the number of operating days and increases in average revenue and direct operating costs per operating day. Average revenue per operating day increased in 2011 primarily due to increases in contractual dayrates. Average direct operating costs per operating day increased in 2011 due primarily to increases in labor costs and repairs and maintenance expense resulting from increased drilling activity. The increase in operating days was due to increased demand largely caused by higher prices for oil. Capital expenditures were incurred in 2011 and 2010 to build new drilling rigs, to modify and upgrade our 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. Depreciation expense increased as a result of capital expenditures.

Pressure Pumping	2011	2010	% Change
	(Dollars in thousands)		
Revenues	$ 379,790	$ 113,115	235.8%
Direct operating costs	$ 247,441	$ 81,096	205.1%
Selling, general and administrative	$ 8,795	$ 5,346	64.5%
Depreciation and amortization	$ 31,836	$ 15,490	105.5%
Operating income	$ 91,718	$ 11,183	720.2%
Fracturing jobs	734	658	11.6%
Other jobs	3,081	2,750	12.0%
Total jobs	3,815	3,408	11.9%
Average revenue per fracturing job	$ 440.48	$ 126.09	249.3%
Average revenue per other job	$ 18.33	$ 10.96	67.2%
Average revenue per total job	$ 99.55	$ 33.19	199.9%
Average direct operating costs per total job	$ 64.86	$ 23.80	172.5%
Capital expenditures	$ 82,616	$ 20,811	297.0%

Contributing to the increases in revenues, direct operating costs, selling, general and administrative expenses and depreciation and amortization was our acquisition of a pressure pumping business on October 1, 2010, which significantly expanded the size of our fleet of pressure pumping equipment and the markets in which we provide pressure pumping services. This acquisition was accounted for as a business combination and the results of operations of the acquired business are included in our pressure pumping segment results from the date of acquisition. The acquired business contributed revenue of $196 million and operating income of $49.9 million to our operating results during the six months ended June 30, 2011.

Our customers have increased their activities in the development of unconventional reservoirs resulting in an increase in larger multi-stage fracturing jobs associated therewith. We have added additional equipment through construction and acquisitions to meet this demand and expand our area of operations. As a result, we have experienced an increase in the number of these larger multi-stage fracturing jobs as a proportion of the total fracturing jobs we performed. Average revenue per fracturing job increased as a result of this increase in the number of larger multi-stage fracturing jobs in 2011 as compared to 2010, as well as increased pricing. Average revenue per other job increased as a result of increased pricing for the services provided and a change in job mix. Average direct operating costs per total job increased primarily as a result of the increase in the number of larger multi-stage fracturing jobs. Selling, general and administrative expenses increased in 2011 due to $3.0 million in expenses associated with the acquired business. Significant capital expenditures have been incurred in recent years to add capacity in our pressure pumping segment. Depreciation and amortization expense in 2011 includes $2.1 million in amortization of intangible assets. The remaining increase in depreciation in 2011 compared to 2010 was a result of our recent capital expenditures and our October 1, 2010 acquisition.

Oil and Natural Gas Production and Exploration		2011	2010	% Change
		(Dollars in thousands, except sales prices)		
Revenues	Oil	$ 21,087	$ 11,407	84.9%
Revenues	Natural gas and liquids	$ 2,754	$ 3,357	(18.0)%
Revenues	Total	$ 23,841	$ 14,764	61.5%
Direct operating costs		$ 4,100	$ 3,842	6.7%
Depletion and impairment		$ 7,794	$ 5,178	50.5%
Operating income		$ 11,947	$ 5,744	108.0%
Capital expenditures		$ 9,746	$ 11,120	(12.4)%

Oil revenues increased due to a higher average sales price and an increase in production of oil. Oil production increased primarily due to the addition of new wells. Natural gas and liquids revenue decreased due to a decline in production. Depletion and impairment expense in 2011 includes approximately $1.4 million of oil and natural gas property impairments compared to approximately $670,000 of oil and natural gas property impairments in 2010. Depletion expense increased approximately $1.9 million in 2011 compared to 2010 primarily due to increased oil production.

Corporate and Other	2011	2010	% Change
	(Dollars in thousands)		
Selling, general and administrative	$ 21,336	$ 16,308	30.8%
Depreciation	$ 1,197	$ 521	129.8%
Net gain on asset disposals	$ (2,621)	$ (21,690)	(87.9)%
Provision for bad debts	$	$ (1,000)	(100.0)%
Interest income	$ 88	$ 1,567	(94.4)%
Interest expense	$ 7,403	$ 2,784	165.9%
Other income	$ 197	$ 249	(20.9)%
Capital expenditures	$ 3,281	$ 3,439	(4.6)%

Selling, general and administrative expense increased in 2011 primarily as a result of increased personnel costs. Gains 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. The gain on asset disposals in 2010 includes a gain of $20.1 million related to the sale of certain rights to explore and develop zones deeper than the depths that we generally target for certain of the oil and natural gas properties in which we have working interests. The negative provision for bad debts in 2010 is the result of collections of certain accounts that had previously been reserved in addition to reductions in our reserve for specific accounts due to improved industry conditions. Interest income in 2010 includes the collection of interest on a customer account as well as interest received on prior overpayments of sales taxes in certain jurisdictions. Interest expense increased in 2011 due to interest charges on the 4.97% Senior Notes that were issued in October 2010 and the term loan that was entered into in August 2010.

Income Taxes

On January 1, 2010, we converted our Canadian operations from a Canadian branch to a controlled foreign corporation for Federal income tax purposes. Because the statutory tax rates in Canada are lower than those in the United States, this transaction triggered a $5.1 million reduction in our deferred tax liabilities, which is being amortized as a reduction to deferred income tax expense over the weighted average remaining useful life of the Canadian assets.

As a result of the above conversion, our Canadian assets are no longer subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, we have elected to permanently reinvest these unremitted earnings in Canada, and we intend to do so for the foreseeable future. As a result, no deferred United States Federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $13.5 million as of June 30, 2011.

Recently Issued Accounting Standards

In June 2011, the FASB issued an accounting standard update that requires that all non-owner changes in stockholders equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income, and the total of comprehensive income. Historically, these components of other comprehensive income and total comprehensive income have been presented in the statement of changes in stockholders equity by many companies, including us. This requirement is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and will be effective for us in the quarter ending March 31, 2012. The adoption of this update will not impact our consolidated financial position, results of operations or cash flows; however it will result in the addition of a new consolidated statement of comprehensive income to our consolidated financial statements.

In May 2011, the FASB issued an accounting standard update to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with United States GAAP and International Financial Reporting Standards. The amendments in this update do not require additional fair value measurements, but provide additional guidance as to measuring fair value as well as certain additional disclosure requirements. The requirements in this update are effective during interim and annual periods beginning after December 15, 2011 and will be effective for us in the quarter ending March 31, 2012. The adoption of this update will not have a material impact on our disclosures included in our consolidated financial statements.

In October 2009, the FASB issued a new accounting standard that addresses the accounting for multiple-deliverable revenue arrangements to enable vendors to account for deliverables separately rather than as a combined unit. This new standard addresses how to separate deliverables and how to measure and allocate arrangement consideration to one or more units of accounting. Existing accounting standards require a vendor to use objective and reliable evidence of fair value for the undelivered items or the residual method to separate deliverables in a multiple-deliverable arrangement. Under the new standard, it is expected that multiple-deliverable arrangements will be separated in more circumstances than under current requirements. The new standard establishes a hierarchy for determining the selling price of a deliverable for purposes of allocating revenue to multiple deliverables. The selling price used will be based on vendor-specific objective evidence if available, third-party evidence if vendor-specific objective evidence is not available, or estimated selling price if neither vendor-specific objective evidence nor third-party evidence is available. The new standard must be prospectively applied to all revenue arrangements entered into in fiscal years beginning on or after June 15, 2010 and became effective for us on January 1, 2011. The adoption of this standard did not have a material impact on our consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting standard update that addresses the disclosure of supplementary pro forma information for business combinations. This update clarifies that when public entities are required to disclose pro forma information for business combinations that occurred in the current reporting period, the pro forma information should be presented as if the business combination occurred as of the beginning of the previous fiscal year when comparative financial statements are presented. This update is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first

annual reporting period beginning on or after December 15, 2010. Early adoption is permitted. We elected to early adopt this update, and this early adoption did not have an impact on the disclosures included in our consolidated financial statements.

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

Our revenue, profitability, financial condition and rate of growth are substantially dependent upon prevailing prices for oil and natural gas. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by market supply and demand factors as well as international military, political and economic conditions, and the ability of OPEC to set and maintain production and price targets. All of these factors are beyond our control. Historically, market prices for natural gas have had the greatest impact on demand for our contract services. During 2008, the monthly average market price of natural gas (monthly average Henry Hub price as reported by the United States Energy Information Administration) peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December. In 2009, the monthly average market price of natural gas declined further to a low of $3.06 per Mcf in September. This decline in the market price of natural gas resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008, and drilling activities remained low throughout 2009 before beginning to recover in 2010. Since then, oil prices have risen significantly and activity levels have increased substantially in shale and other plays directed at oil and liquids. Construction of new land drilling rigs in the United States during the last ten years has significantly contributed to excess capacity. As a result of these factors, our average number of rigs operating has declined from historic highs. 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. Low market prices for oil and natural gas would likely result in lower demand for our drilling rigs and pressure pumping services and adversely affect our operating results, financial condition and cash flows.

The North American oil and natural gas services industry has experienced downturns in demand during the last decade. 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.

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 our term credit facility or our revolving credit facility. 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 2.75% to 3.75% and the margin on base rate loans ranges from 1.75% to 2.75%, based on our debt to capitalization ratio. At June 30, 2011, the margin on LIBOR loans was 2.75% and the margin on base rate loans was 1.75%. As of June 30, 2011, we had no borrowings outstanding under our revolving credit facility and $96.3 million outstanding under our term credit facility at an interest rate of 3.125%. The interest rate on the borrowing outstanding under our term credit facility is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate. A one percent increase in the interest rate on the borrowing outstanding under our term credit facility as of June 30, 2011 would increase our annual cash interest expense by approximately $963,000.

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 June 30, 2011.

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 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 June 30, 2011.

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)
April 1-30, 2011 (2)	40,812	$ 31.18		$ 113,123
May 1-31, 2011 (2)	51	$ 31.69		$ 113,123
June 1-30, 2011 (2)	97,050	$ 30.11	8,025	$ 112,882
Total	137,913	$ 30.43	8,025	$ 112,882

(1) On August 2, 2007, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions.

(2) We purchased 40,812 shares in April, 51 shares in May and 89,025 shares in June from employees to provide the respective employees with the funds necessary to satisfy their tax withholding obligations with respect to the vesting of restricted shares. The price paid was the closing price of our common stock on the last business day prior to the date the shares vested. These purchases were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan and not pursuant to the stock buyback program.

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).
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 June 30, 2011, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Stockholders Equity, (iv) the Consolidated Statements of Cash Flows, and (v) Notes to 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/ Gregory W. Pipkin
Gregory W. Pipkin
Chief Accounting Officer and Assistant Secretary
(Principal Accounting Officer and Duly Authorized Officer)

DATE: August 1, 2011