PIONEER ENERGY SERVICES CORP
Form 10-Q
August 07, 2012

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

FORM 10-Q

(Mark one)

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

For the quarterly period ended June 30, 2012

or

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

Commission File Number: 1-8182

PIONEER ENERGY SERVICES CORP.
(Exact name of registrant as specified in its charter)

TEXAS (State or other jurisdiction of incorporation or organization)	74-2088619 (I.R.S. Employer Identification Number)
1250 NE Loop 410, Suite 1000 San Antonio, Texas (Address of principal executive offices)	78209 (Zip Code)

Registrant’s telephone number, including area code: (210) 828-7689
Registrant's former name: Pioneer Drilling Company

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 o

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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	o
Non-accelerated filer (Do not check if a small reporting company.)	o	Smaller reporting company	o

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

As of July 20, 2012, there were 62,022,191 shares of common stock, par value $0.10 per share, of the registrant issued and outstanding.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2012 (Unaudited)	December 31, 2011 (Audited)
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$20,380	$86,197
Receivables:		
Trade, net of allowance for doubtful accounts	128,950	106,084
Unbilled receivables	31,267	31,512
Insurance recoveries	5,693	5,470
Income taxes	1,583	2,168
Deferred income taxes	14,350	15,433
Inventory	13,211	11,184
Prepaid expenses and other current assets	13,333	11,564
Total current assets	228,767	269,612
Property and equipment, at cost	1,550,277	1,336,926
Less accumulated depreciation	610,832	542,970
Net property and equipment	939,445	793,956
Intangible assets, net of amortization	48,205	52,680
Goodwill	41,683	41,683
Noncurrent deferred income taxes	1,242	735
Other long-term assets	12,066	14,088
Total assets	$1,271,408	$1,172,754
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$95,189	$66,440
Current portion of long-term debt	871	872
Prepaid drilling contracts	4,071	3,966
Accrued expenses:		
Payroll and related employee costs	24,965	29,057
Insurance premiums and deductibles	9,741	10,583
Insurance claims and settlements	5,580	5,470
Interest	12,269	12,283
Other	14,199	11,009
Total current liabilities	166,885	139,680
Long-term debt, less current portion	453,290	418,728
Noncurrent deferred income taxes	105,689	94,745
Other long-term liabilities	7,607	9,156
Total liabilities	733,471	662,309
Commitments and contingencies (Note 8)		
Shareholders' equity:		

Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock $.10 par value; 100,000,000 shares authorized; 62,018,191 shares and 61,782,180 shares outstanding at June 30, 2012 and December 31, 2011, respectively	6,215	6,188
Additional paid-in capital	445,985	442,020
Treasury stock, at cost; 134,188 shares and 95,409 shares at June 30, 2012 and December 31, 2011, respectively	(1,261)	(904)
Accumulated earnings	86,998	63,141
Total shareholders' equity	537,937	510,445
Total liabilities and shareholders' equity	$1,271,408	$1,172,754

See accompanying notes to condensed consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	(In thousands, except per share data)			
Revenues:				
Drilling services	$119,048	$106,523	$243,352	$206,279
Production services	110,776	64,762	218,450	118,355
Total revenues	229,824	171,285	461,802	324,634
Costs and expenses:				
Drilling services	78,631	73,190	159,708	140,699
Production services	65,683	37,754	126,379	70,982
Depreciation and amortization	39,989	32,424	78,362	64,680
General and administrative	22,265	15,860	43,408	30,381
Bad debt (recovery) expense	(56)	139	(147)	55
Impairment of equipment	—	—	1,032	—
Total costs and expenses	206,512	159,367	408,742	306,797
Income from operations	23,312	11,918	53,060	17,837
Other (expense) income:				
Interest expense	(7,650)	(7,983)	(17,205)	(15,522)
Other	20	754	952	(5,763)
Total other expense	(7,630)	(7,229)	(16,253)	(21,285)
Income (loss) before income taxes	15,682	4,689	36,807	(3,448)
Income tax (expense) benefit	(5,997)	(1,039)	(12,950)	1,063
Net income (loss)	$9,685	$3,650	$23,857	$(2,385)
Income (loss) per common share—Basic	$0.16	$0.07	$0.39	$(0.04)
Income (loss) per common share—Diluted	$0.15	$0.07	$0.38	$(0.04)
Weighted average number of shares outstanding—Basic	61,768	54,205	61,673	54,087
Weighted average number of shares outstanding—Diluted	62,620	55,881	62,624	54,087

See accompanying notes to condensed consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six months ended June 30, 2012	2011
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$23,857	$(2,385)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	78,362	64,680
Allowance for doubtful accounts	370	56
Loss (gain) on dispositions of property and equipment	(1,004)	691
Stock-based compensation expense	3,670	3,483
Amortization of debt issuance costs, discount and premium	1,475	2,044
Impairment of equipment	1,032	—
Deferred income taxes	11,221	(2,843)
Change in other long-term assets	744	1,432
Change in other long-term liabilities	(1,549)	1,655
Changes in current assets and liabilities:		
Receivables	(22,518)	(26,800)
Inventory	(2,027)	(1,635)
Prepaid expenses and other current assets	(1,560)	(990)
Accounts payable	1,279	7,411
Prepaid drilling contracts	105	1,121
Accrued expenses	(1,759)	5,691
Net cash provided by operating activities	91,698	53,611
Cash flows from investing activities:		
Acquisition of production services businesses	—	(2,000)
Purchases of property and equipment	(193,884)	(79,196)
Proceeds from sale of property and equipment	1,957	2,000
Proceeds from sale of auction rate securities	—	12,569
Net cash used in investing activities	(191,927)	(66,627)
Cash flows from financing activities:		
Debt repayments	(863)	(13,742)
Proceeds from issuance of debt	35,000	17,000
Debt issuance costs	(23)	(3,186)
Proceeds from exercise of options	655	2,091
Purchase of treasury stock	(357)	(352)
Excess tax benefit of stock option exercises	—	696
Net cash provided by financing activities	34,412	2,507
Net decrease in cash and cash equivalents	(65,817)	(10,509)
Beginning cash and cash equivalents	86,197	22,011
Ending cash and cash equivalents	$20,380	$11,502
Supplementary disclosure:		
Interest paid	$21,783	$13,781
Income tax paid	$823	$409

See accompanying notes to condensed consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies

Business and Principles of Consolidation

On July 30, 2012, we changed our company name from "Pioneer Drilling Company" to "Pioneer Energy Services Corp." Our common stock will continue to trade on the New York Stock Exchange, but our ticker symbol has changed from "PDC" to "PES". Our company name change reinforces our strategy to expand our service offerings beyond drilling services, which has been our core, legacy business. Pioneer Energy Services provides drilling services and production services to independent and major oil and gas exploration and production companies throughout much of the onshore oil and gas producing regions of the United States and internationally in Colombia.

Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies with its fleet of 66 drilling rigs which are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	15
East Texas	3
West Texas	20
North Dakota	11
Utah	5
Appalachia	4
Colombia	8
	66

Drilling revenues and rig utilization have steadily improved since late 2009, primarily due to increased demand for drilling services in domestic shale plays and oil or liquid rich regions. We capitalized on this trend by moving drilling rigs in our fleet to these higher demand regions from lower demand regions. As a result, we closed our Oklahoma and North Texas drilling divisions during 2011 and established our West Texas drilling division in early 2011.

In 2011, we began construction, based on term contracts, on ten new-build AC drilling rigs that are fit for purpose for domestic shale plays. Construction has been completed for four of these new-build drilling rigs, three of which began operating under their term contracts in June and July 2012. We expect another four of the new-build drilling rigs to begin working by the end of 2012, with the remaining three during the first quarter of 2013. As of July 20, 2012, 54 drilling rigs are operating under drilling contracts, 45 of which are under term contracts, and one completed new-build drilling rig is under contract to begin working in the third quarter of 2012. We are actively marketing all our idle drilling rigs.

In March 2012, we evaluated the drilling rigs in our fleet that had remained idle and decided to retire two mechanical drilling rigs that were assigned to our East Texas drilling division, with most of their components to be used for spare equipment. We recognized an impairment charge of $0.6 million in March 2012 in association with our decision to retire these two drilling rigs.

In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with clients. Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed.

Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services, coiled tubing services, and fishing and rental services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. As of July 20, 2012, we have a fleet of 101 well servicing rigs consisting of ninety 550 horsepower rigs, ten 600 horsepower rigs and one 400 horsepower rig. All our well servicing rigs are currently operating

3

or are being actively marketed. We currently provide wireline services and coiled tubing services with a fleet of 117 wireline units and 11 coiled tubing units, and we provide rental services with approximately $15.6 million of fishing and rental tools. We plan to add another seven well servicing rigs, three wireline units and two coiled tubing units by the end of 2012. In March 2012, we decided to retire two older wireline units and certain wireline equipment resulting in an impairment charge of approximately $0.4 million.

The accompanying unaudited condensed consolidated financial statements include the accounts of Pioneer Energy Services Corp. and our wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of our management, all adjustments (consisting of normal, recurring accruals) necessary for a fair presentation have been included. In preparing the accompanying unaudited condensed consolidated financial statements, we make various estimates and assumptions that affect the amounts of assets and liabilities we report as of the dates of the balance sheets and income and expenses we report for the periods shown in the income statements and statements of cash flows. Our actual results could differ significantly from those estimates. Material estimates that are particularly susceptible to significant changes in the near term relate to our recognition of revenues and costs for turnkey contracts, our estimate of the allowance for doubtful accounts, our estimate of the liability relating to the self-insurance portion of our health and workers’ compensation insurance, our estimate of asset impairments, our estimate of deferred taxes, our estimate of compensation related accruals and our determination of depreciation and amortization expense. The condensed consolidated balance sheet as of December 31, 2011 has been derived from our audited financial statements. We suggest that you read these condensed consolidated financial statements together with the consolidated financial statements and the related notes included in our annual report on Form 10-K for the fiscal year ended December 31, 2011.

In preparing the accompanying unaudited condensed consolidated financial statements, we have reviewed events that have occurred after June 30, 2012, through the filing of this Form 10-Q, for inclusion as necessary.

Recently Issued Accounting Standards

Fair Value Measurement. In May 2011, the FASB issued ASU No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This update clarifies existing guidance about how fair value should be applied where it already is required or permitted and provides wording changes that align this standard with International Financial Reporting Standards (IFRS). We are required to apply this guidance prospectively beginning with our first quarterly filing in 2012. The adoption of this new guidance has not had an impact on our financial position or results of operations.

Comprehensive Income. In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income. This update increases the prominence of other comprehensive income in financial statements, eliminating the option of presenting other comprehensive income in the statement of changes in equity, and instead, requiring the components of net income and comprehensive income to be presented in either one or two consecutive financial statements. We are required to comply with this guidance prospectively beginning with our first quarterly filing in 2012. We have not recognized any other comprehensive income during either of the six month periods ended June 30, 2012 or 2011. The adoption of this new guidance has not had an impact on our financial position or results of operations.

In December 2011, the FASB issued ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05. This update delays the effective date of the requirement to present reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements.

Intangibles–Goodwill and Other. In September 2011, the FASB issued ASU No. 2011-08, Intangibles–Goodwill and Other (Topic 350): Testing Goodwill for Impairment. This update allows entities testing goodwill for impairment the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step goodwill impairment test). If entities determine, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step impairment test would be required. The amendments are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this new guidance has not had an impact on our financial position or results of operations.

Drilling Contracts

Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. Generally, our contracts provide for the drilling of a single well and typically permit the client to terminate on short notice. During periods of high rig demand, or for our newly constructed rigs, we enter into longer-term drilling contracts. Currently, we have contracts with terms of six months to four years in duration. As of July 20, 2012, we have 45 drilling rigs operating under term contracts, including three of the new-build AC drilling rigs. Of these 45 contracts, if not renewed at the end of their terms, 29 will expire by January 20, 2013 (which includes six drilling rigs in Colombia), 11 will expire by July 20, 2013, two will expire by January 20, 2014, two will expire by July 20, 2014 and one will expire by July 20, 2016. We currently have term contracts for another seven new-build AC drilling rigs that are fit for purpose for domestic shale plays. Three of the new-build drilling rigs are currently working under term contracts and we expect another four to begin working by the end of 2012, with the remaining three during the first quarter of 2013.

Restricted Cash

As of June 30, 2012, we had restricted cash in the amount of $0.7 million held in an escrow account to be used for a future payment due March 2013 in connection with the acquisition of Prairie Investors d/b/a Competition Wireline (“Competition”). Restricted cash of $0.7 million is recorded in other current assets and the associated obligation of $0.7 million is recorded in accrued expenses.

Investments

At December 31, 2010, we held $15.9 million (par value) of auction rate preferred securities (“ARPSs”), which were variable-rate preferred securities with a long-term maturity that were classified as held for sale. On January 19, 2011, we entered into an agreement with a financial institution to sell the ARPSs for $12.6 million, which represented 79% of the par value, plus accrued interest. Under the ARPSs sales agreement, we retained the unilateral right for a period ending January 7, 2013 to: (a) repurchase all the ARPSs that were sold at the $12.6 million price at which they were initially sold to the financial institution; and (b) if not repurchased, receive additional proceeds from the financial institution upon redemption of the ARPSs by the original issuer of these securities (collectively, the “ARPSs Call Option”). Upon origination, the fair value of the ARPSs Call Option was estimated to be $0.6 million and was recognized as other income in our consolidated statement of operations for 2011. We are required to assess the value of the ARPSs Call Option at the end of each reporting period, with any changes in fair value recorded within our consolidated statement of operations. As of June 30, 2012, the ARPSs Call Option had an estimated fair value of $0.2 million, and was included in our prepaid expenses and other current assets in our condensed consolidated balance sheet.

Property and Equipment

As of June 30, 2012, we have incurred $210.7 million in construction costs for ongoing projects, primarily for our new-build drilling rigs. During the six months ended June 30, 2012, we capitalized $6.0 million of interest costs, primarily related to the new-build drilling rigs.

2. Acquisitions

On December 31, 2011, we acquired Go-Coil, L.L.C., a Louisiana limited liability company (“Go-Coil”) which provided coiled tubing services with a fleet of seven onshore units and three offshore units through its facilities in Louisiana, Texas, Oklahoma and Pennsylvania. The aggregate purchase price for the acquisition was approximately $110.4 million, which consisted of assets acquired of $114.9 million and liabilities assumed of $4.5 million. We funded the acquisition with cash on hand that was primarily generated from the proceeds of the Senior Notes issued in November 2011, as described in Note 3, Long-term Debt.

The following table summarizes the allocation of the purchase price to the estimated fair value of the assets acquired and liabilities assumed as of the date of acquisition (amounts in thousands):

Cash acquired	$313
Other current assets	9,068
Property and equipment	30,103
Intangibles and other assets	33,695
Goodwill	41,683
Total assets acquired	$114,862
Current liabilities	$4,337
Long-term debt	131
Total liabilities assumed	$4,468
Net assets acquired	$110,394

The acquisition of the coiled tubing services business from Go-Coil was accounted for as an acquisition of a business in accordance with ASC Topic 805, Business Combinations. The purchase price allocation for the Go-Coil acquisition was finalized as of June 30, 2012. Goodwill was recognized as part of the Go-Coil acquisition, since the purchase price exceeded the estimated fair value of the assets acquired and liabilities assumed. We believe that the goodwill relates to the acquired workforce, future synergies between our existing service offerings and the ability to expand our service offerings.

3. Long-term Debt

Long-term debt consists of the following (amounts in thousands):

	June 30, 2012	December 31, 2011
Senior secured revolving credit facility	$35,000	$—
Senior notes	418,170	417,747
Other notes payable	991	1,853
	454,161	419,600
Less current portion	(871)	(872)
	$453,290	$418,728

Senior Secured Revolving Credit Facility

We have a credit agreement, as amended on June 30, 2011, with Wells Fargo Bank, N.A. and a syndicate of lenders which provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of $250 million, all of which matures on June 30, 2016 (the "Revolving Credit Facility"). The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and letter of credit exposure, but in no event will reduce the borrowing availability under the Revolving Credit Facility to less than $250 million.

Borrowings under the Revolving Credit Facility bear interest, at our option, at the LIBOR rate or at the bank prime rate, plus an applicable per annum margin that ranges from 2.50% to 3.25% and 1.50% to 2.25%, respectively. The LIBOR margin and bank prime rate margin in effect at July 20, 2012 are 2.75% and 1.75%, respectively. The Revolving Credit Facility requires a commitment fee due quarterly based on the average daily unused amount of the commitments of the lenders, a fronting fee due for each letter of credit issued, and a quarterly letter of credit fee due based on the average undrawn amount of letters of credit outstanding during such period.

Our obligations under the Revolving Credit Facility are secured by substantially all of our domestic assets (including equity interests in Pioneer Global Holdings, Inc. and 65% of the outstanding equity interests of any first-tier foreign subsidiaries owned by Pioneer Global Holdings, Inc., but excluding any equity interest in, and any assets of, Pioneer Services Holdings, LLC and Pioneer Coiled Tubing Services, LLC) and are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Borrowings under the Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.

6

As of July 20, 2012, we had $35.0 million outstanding under our Revolving Credit Facility and $9.0 million in committed letters of credit, which resulted in borrowing availability of $206.0 million under our Revolving Credit Facility. There are no limitations on our ability to access this borrowing capacity other than maintaining compliance with the covenants under the Revolving Credit Facility. At June 30, 2012, we were in compliance with our financial covenants. Our total consolidated leverage ratio was 1.9 to 1.0, our senior consolidated leverage ratio was 0.2 to 1.0, and our interest coverage ratio was 8.0 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum total consolidated leverage ratio that cannot exceed 4.00 to 1.00;
- A maximum senior consolidated leverage ratio, which excludes unsecured and subordinated debt, that cannot exceed 2.50 to 1.00;
- A minimum interest coverage ratio that cannot be less than 2.50 to 1.00; and
- If our senior consolidated leverage ratio is greater than 2.00 to 1.00 at the end of any fiscal quarter, our minimum asset coverage ratio cannot be less than 1.00 to 1.00.

The Revolving Credit Facility does not restrict capital expenditures as long as (a) no event of default exists under the Revolving Credit Facility or would result from such capital expenditures, (b) after giving effect to such capital expenditures there is availability under the Revolving Credit Facility equal to or greater than $25 million and (c) the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is less than 2.00 to 1.00. If the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is equal to or greater than 2.00 to 1.00, then capital expenditures are limited to $100 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $30 million.

At June 30, 2012, our senior consolidated leverage ratio was not greater than 2.00 to 1.00 and therefore, we were not subject to the capital expenditure threshold restrictions listed above.

The Revolving Credit Facility has additional restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. In addition, the Revolving Credit Facility contains customary events of default, including without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness in excess of specified amounts, certain events of bankruptcy and insolvency, judgment defaults in excess of specified amounts, failure of any guaranty or security document supporting the credit agreement and change of control.

Senior Notes

On March 11, 2010, we issued $250 million of unregistered senior notes with a coupon interest rate of 9.875% that are due in 2018 (the “2010 Senior Notes”). The 2010 Senior Notes were sold with an original issue discount of $10.6 million that was based on 95.75% of their face value, which will result in an effective yield to maturity of approximately 10.677%. On March 11, 2010, we received $234.8 million of net proceeds from the issuance of the 2010 Senior Notes after deductions were made for the $10.6 million of original issue discount and $4.6 million for underwriters’ fees and other debt offering costs. The net proceeds were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility.

On November 21, 2011, we issued $175 million of unregistered Senior Notes (the “2011 Senior Notes”). The 2011 Senior Notes have the same terms and conditions as the 2010 Senior Notes. The 2011 Senior Notes were sold with an original issue premium of $1.8 million that was based on 101% of their face value, which will result in an effective yield to maturity of approximately 9.66%. On November 21, 2011, we received $172.7 million of net proceeds from the issuance of the 2011 Senior Notes, including the original issue premium, and after $4.1 million of deductions were made for underwriters' fees and other debt offering costs. A portion of the net proceeds were used to fund the acquisition of Go-Coil in December 2011, as described in Note 2, Acquisitions.

In accordance with a registration rights agreement with the holders of both our 2010 Senior Notes and 2011 Senior Notes, we filed exchange offer registration statements on Form S-4 with the Securities and Exchange Commission that became effective on September 2, 2010 and July 13, 2012, respectively. These exchange offer registration statements enabled the holders of both our 2010 Senior Notes and 2011 Senior Notes to exchange their senior notes for publicly registered notes with substantially identical terms. References to the “2010 Senior Notes” and “2011 Senior Notes” herein include the senior notes issued in the exchange offers.

The 2010 and 2011 Senior Notes (the “Senior Notes”) are reflected on our condensed consolidated balance sheet at June 30, 2012 with a total carrying value of $418.2 million, which represents the $425.0 million total face value net of the $8.4 million unamortized portion of original issue discount and $1.6 million unamortized portion of original issue premium. The original issue discount and premium are being amortized over the term of the Senior Notes based on the effective interest method.

The Senior Notes will mature on March 15, 2018 with interest due semi-annually in arrears on March 15 and September 15 of each year. We have the option to redeem the Senior Notes, in whole or in part, at any time on or after March 15, 2014 in each case at the redemption price specified in the Indenture dated March 11, 2010 (the “Indenture”) together with any accrued and unpaid interest to the date of redemption. Prior to March 15, 2014, we may also redeem the Senior Notes, in whole or in part, at a “make-whole” redemption price specified in the Indenture, together with any accrued and unpaid interest to the date of redemption. In addition, prior to March 15, 2013, we may, on one or more occasions, redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price of 109.875% of the principal amount, plus any accrued and unpaid interest to the redemption date, with the net proceeds of certain equity offerings, if at least 65% of the aggregate principal amount of the Senior Notes remains outstanding after such redemption and the redemption occurs within 120 days of the closing of the equity offering.

Upon the occurrence of a change of control, holders of the Senior Notes will have the right to require us to purchase all or a portion of the Senior Notes at a price equal to 101% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase. Under certain circumstances in connection with asset dispositions, we will be required to use the excess proceeds of asset dispositions to make an offer to purchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase.

The Indenture contains certain restrictions generally on our and certain of our subsidiaries’ ability to:

- pay dividends on stock;
- repurchase stock or redeem subordinated debt or make other restricted payments;
- incur, assume or guarantee additional indebtedness or issue disqualified stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- pay dividends, engage in loans, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person;
- enter into transactions with affiliates; and
- enter into new lines of business.

We were in compliance with these covenants as of June 30, 2012. The Senior Notes are not subject to any sinking fund requirements. The Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by certain of our existing domestic subsidiaries and by certain of our future domestic subsidiaries (see Note 9, Guarantor/Non-Guarantor Condensed Consolidated Financial Statements).

Other Notes Payable

We have two notes payable to certain employees that are former shareholders of production services businesses which we have acquired. These notes payable have interest rates of 6% and 14%, require annual payments of principal and interest and have final maturity dates in March and April 2013. We have other debt of $0.1 million as of June 30, 2012 which represents a capital lease obligation for equipment, with monthly payments due through November 2016.

Debt Issuance Costs

Costs incurred in connection with the Revolving Credit Facility and the Senior Notes were capitalized and are being amortized using the straight-line method over the term of the Revolving Credit Facility which matures in June 2016. Costs incurred in connection with the issuance of our Senior Notes were capitalized and are being amortized using the straight-line method (which approximates the use of the interest method) over the term of the Senior Notes which mature in March 2018. Capitalized debt costs related to the issuance of our long-term debt were approximately $10.6 million and $11.6 million as of June 30, 2012 and December 31, 2011, respectively. We recognized approximately $1.1 million and $1.0 million of associated amortization during the six months ended June 30, 2012 and 2011, respectively. In June 2011, we recognized additional amortization expense related to the write-off of $0.6 million of debt issuance costs, representing the portion of unamortized debt issuance costs associated with certain syndicate lenders who are no longer participating in the Revolving Credit Facility as amended on June 30, 2011.

4. Fair Value of Financial Instruments

ASC Topic 820, Fair Value Measurements and Disclosures, defines fair value and provides a hierarchal framework associated with the level of subjectivity used in measuring assets and liabilities at fair value.

At June 30, 2012 and December 31, 2011, our financial instruments consist primarily of cash, trade receivables, trade payables, long-term debt, and our ARPSs Call Option. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term nature of these instruments.

At June 30, 2012, our ARPSs Call Option is reported at an amount that reflects our current estimate of fair value. To estimate the value of our ARPSs Call Option as of June 30, 2012, we used inputs defined by ASC Topic 820 as level 3 inputs, which are significant unobservable inputs. The fair value of the ARPSs Call Option was estimated using a modified Black-Scholes model, based on an analysis of recent historical transactions for securities with similar characteristics to the underlying ARPSs, and an analysis of the probability that the options would be exercisable as a result of the underlying ARPSs being redeemed or traded in a secondary market at an amount greater than the option price before the expiration date. As of June 30, 2012, the ARPSs Call Option had an estimated fair value of $0.2 million, and was included in our prepaid expenses and other current assets in our consolidated balance sheet. Future changes in the fair values of the ARPSs Call Option will be reflected in other income (expense) in our condensed consolidated statements of operations.

The fair value of our long-term debt at June 30, 2012 and December 31, 2011 is estimated using a discounted cash flow analysis, based on rates that we believe we would currently pay for similar types of debt instruments. This discounted cash flow analysis based on inputs defined by ASC Topic 820 as level 2 inputs, which are observable inputs for similar types of debt instruments. The following table presents the supplemental fair value information about long-term debt at June 30, 2012 and December 31, 2011 (amounts in thousands):

	June 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	$454,161	$490,392	$419,600	$443,309

5. Earnings (Loss) Per Common Share

The following table presents a reconciliation of the numerators and denominators of the basic income (loss) per share and diluted income (loss) per share computations (amounts in thousands, except per share data):

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Basic				
Net income (loss)	$9,685	$3,650	$23,857	$(2,385)
Weighted-average shares	61,768	54,205	61,673	54,087
Income (loss) per share	$0.16	$0.07	$0.39	$(0.04)
Diluted				
Net income (loss)	$9,685	$3,650	$23,857	$(2,385)
Effect of dilutive securities	—	—	—	—
Net income (loss) available to common shareholders after assumed conversion	$9,685	$3,650	$23,857	$(2,385)
Weighted average shares:				
Outstanding	61,768	54,205	61,673	54,087
Diluted effect of stock options, restricted stock, and restricted stock unit awards	852	1,676	951	—
	62,620	55,881	62,624	54,087
Income (loss) per share	$0.15	$0.07	$0.38	$(0.04)

Potentially dilutive stock options, restricted stock and restricted stock unit awards representing a total of 4,416,886 and 2,153,147 shares of common stock for the three months ended June 30, 2012 and 2011, respectively, and

4,309,528 and 2,916,322 for the six months ended June 30, 2012 and 2011, respectively, were excluded from the computation of diluted weighted average shares outstanding due to their antidilutive effect.

6. Equity Transactions and Stock Based Compensation Plans

Stock-based Compensation Plans

We grant stock option awards with vesting based on time of service conditions and we grant restricted stock unit awards with vesting based on time of service conditions, and in certain cases, subject to performance and market conditions. We recognize compensation cost for stock option, restricted stock and restricted stock unit awards based on the fair value estimated in accordance with ASC Topic 718, Compensation—Stock Compensation. For our awards with graded vesting, we recognize compensation expense on a straight-line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards.

Stock Options

We grant stock option awards which generally become exercisable over a three-year period and expire ten years after the date of grant. Our stock-based compensation plans require that all stock option awards have an exercise price that is not less than the fair market value of our common stock on the date of grant. We issue shares of our common stock when vested stock option awards are exercised.

We estimate the fair value of each option grant on the date of grant using a Black-Scholes options-pricing model. The following table summarizes the assumptions used in the Black-Scholes option-pricing model based on a weighted-average calculation for the three and six months ended June 30, 2012 and 2011:

	Three months ended June 30,				Six months ended June 30,			
	2012		2011		2012		2011	
Expected volatility	68	%	68	%	70	%	65	%
Risk-free interest rates	0.4	%	1.8	%	0.8	%	1.5	%
Expected life in years	3.50		4.00		5.12		4.33	
Options granted	55,000		5,000		530,156		602,298	
Grant-date fair value	$3.35		$7.18		$5.02		$4.69	

The assumptions above are based on multiple factors, including historical exercise patterns of homogeneous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for these same homogeneous groups and volatility of our stock price. As we have not declared dividends since we became a public company, we did not use a dividend yield. In each case, the actual value that will be realized, if any, will depend on the future performance of our common stock and overall stock market conditions. There is no assurance the value an optionee actually realizes will be at or near the value we have estimated using the Black-Scholes options-pricing model.

The following table summarizes the compensation expense recognized for stock option awards during the three and six months ended June 30, 2012 and 2011 (amounts in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
General and administrative expense	$637	$897	$1,556	$1,893
Operating costs	8	56	52	137
	$645	$953	$1,608	$2,030

During the three and six months ended June 30, 2012, 95,166 and 163,266 stock options were exercised at a weighted-average exercise price of $4.22 and $4.01, respectively. During the three and six months ended June 30, 2011, 184,512 and 311,812 stock options were exercised at a weighted-average exercise price of $8.29 and $6.71, respectively. We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the fair market value of our stock on the date of exercise over the exercise price of the options. In accordance with ASC Topic 718, we reported all excess tax benefits resulting from the exercise of stock options as financing cash flows in our condensed consolidated statement of cash flows.

Restricted Stock

We grant restricted stock awards that vest over a three-year period with a fair value based on the closing price of our common stock on the date of the grant. When restricted stock awards are granted, or when restricted stock unit awards are converted to restricted stock, shares of our common stock are considered issued, but subject to certain restrictions. During the six months ended June 30, 2012 and 2011, we granted 49,748 and 32,360 shares of restricted stock awards, with a weighted-average grant-date price of $8.04 and $12.36, respectively. During the three months ended June 30, 2011, we issued an additional 166,918 shares of restricted stock upon the conversion of performance-based RSU awards, as described below.

The following table summarizes the compensation expense recognized for restricted stock awards during the three and six months ended June 30, 2012 and 2011 (amounts in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
General and administrative expense	$179	$291	$395	$451
Operating costs	13	17	28	42
	$192	$308	$423	$493

Restricted Stock Units

We grant restricted stock unit awards with vesting based on time of service conditions only (“time-based RSUs”), and we grant restricted stock unit awards with vesting based on time of service, which are also subject to performance and market conditions (“performance-based RSUs”). Shares of our common stock are issued to recipients of restricted stock units only when they have satisfied the applicable vesting conditions.

Our time-based RSUs generally vest over a three-year period, with fair values based on the closing price of our common stock on the date of grant. The following table summarizes the number and weighted-average grant-date fair value of the time-based RSUs granted during the three and six months ended June 30, 2012 and 2011:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Time-based RSUs granted	151,500	130,570	356,813	233,473
Weighted-average grant-date fair value	$7.04	$12.51	$8.21	$10.97

Our performance-based RSUs are granted at a target number of issuable shares, for which the final number of shares of common stock is adjusted based on our actual achievement levels that are measured against predetermined performance conditions. There were no grants of performance-based RSUs during the three months ended June 30, 2012 or 2011. The following table summarizes the number and weighted-average grant-date fair value of performance-based RSUs granted during the six months ended June 30, 2012 and 2011:

	Six months ended June 30,	
	2012	2011
Performance-based RSUs granted	221,495	146,479
Weighted-average grant-date fair value	$9.85	$10.23

Performance-based RSUs granted during the six months ended June 30, 2012 and 2011 will cliff vest after 39 months from the date of grant. The number of shares of common stock awarded will be based upon the Company’s achievement of certain performance conditions, as compared to a predefined peer group, over the respective performance period. Approximately one-third of the performance-based RSUs are subject to a market condition, and therefore the fair value of these awards is measured using a Monte Carlo simulation model. Compensation expense for awards with a market condition is reduced only for estimated forfeitures; no adjustment to expense is otherwise made, regardless of the number of shares issued, if any. The remaining two-thirds of the performance-based RSUs are subject to performance conditions, and therefore the fair value is based on the closing price of our common stock on the date of grant, applied to the estimated number of shares that will be awarded. Compensation expense ultimately recognized for awards with performance conditions will be equal to the fair value of the restricted stock unit award based on the actual outcome of the service and performance conditions.

11

The following table summarizes the compensation expense recognized for restricted stock unit awards during the three and six months ended June 30, 2012 and 2011 (amounts in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
General and administrative expense	$744	$433	$1,402	$824
Operating costs	89	75	237	136
	$833	$508	$1,639	$960

7. Segment Information

We have two operating segments referred to as the Drilling Services Segment and the Production Services Segment which is the basis management uses for making operating decisions and assessing performance.

Drilling Services Segment—Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies with its fleet of 66 drilling rigs which are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	15
East Texas	3
West Texas	20
North Dakota	11
Utah	5
Appalachia	4
Colombia	8
	66

Production Services Segment—Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services, coiled tubing services, and fishing and rental services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. We currently have a fleet of 101 well servicing rigs consisting of ninety 550 horsepower rigs, ten 600 horsepower rigs and one 400 horsepower rig. We currently provide wireline services and coiled tubing services with a fleet of 117 wireline units and 11 coiled tubing units, and we provide rental services with approximately $15.6 million of fishing and rental tools.

The following tables set forth certain financial information for our two operating segments and corporate as of and for the three and six months ended June 30, 2012 and 2011 (amounts in thousands):

	As of and for the three months ended June 30, 2012			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$803,264	$432,584	$35,560	$1,271,408
Revenues	$119,048	$110,776	$—	$229,824
Operating costs	78,631	65,683	—	144,314
Segment margin	$40,417	$45,093	$—	$85,510
Depreciation and amortization	$26,307	$13,391	$291	$39,989
Capital expenditures	$80,608	$27,634	$734	$108,976

	As of and for the three months ended June 30, 2011			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$609,886	$254,901	$23,649	$888,436
Revenues	$106,523	$64,762	$—	$171,285
Operating costs	73,190	37,754	—	110,944
Segment margin	$33,333	$27,008	$—	$60,341
Depreciation and amortization	$24,702	$7,510	$212	$32,424
Capital expenditures	$46,306	$17,301	$199	$63,806

	As of and for the six months ended June 30, 2012			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$803,264	$432,584	$35,560	$1,271,408
Revenues	$243,352	$218,450	$—	$461,802
Operating costs	159,708	126,379	—	286,087
Segment margin	$83,644	$92,071	$—	$175,715
Depreciation and amortization	$51,796	$26,109	$457	$78,362
Capital expenditures	$161,192	$59,188	$973	$221,353

	As of and for the six months ended June 30, 2011			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$609,886	$254,901	$23,649	$888,436
Revenues	$206,279	$118,355	$—	$324,634
Operating costs	140,699	70,982	—	211,681
Segment margin	$65,580	$47,373	$—	$112,953
Depreciation and amortization	$49,188	$15,005	$487	$64,680
Capital expenditures	$65,417	$32,745	$338	$98,500

The following table reconciles the segment profits reported above to income from operations as reported on the consolidated statements of operations for the three and six months ended June 30, 2012 and 2011 (amounts in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Segment margin	$85,510	$60,341	$175,715	$112,953
Depreciation and amortization	(39,989)	(32,424)	(78,362)	(64,680)
General and administrative	(22,265)	(15,860)	(43,408)	(30,381)
Bad debt recovery (expense)	56	(139)	147	(55)
Impairment of equipment	—	—	(1,032)	—
Income from operations	$23,312	$11,918	$53,060	$17,837

The following table sets forth certain financial information for our international operations in Colombia as of and for the three and six months ended June 30, 2012 and 2011 which is included in our Drilling Services Segment (amounts in thousands):

	As of and for the three months ended June 30,		As of and for the six months ended June 30,	
	2012	2011	2012	2011
Identifiable assets	$149,305	$159,701	$149,305	$159,701
Revenues	$22,485	$29,241	$46,301	$53,476

Identifiable assets for our international operations in Colombia include five drilling rigs that are owned by our Colombia subsidiary and three drilling rigs that are owned by one of our domestic subsidiaries and leased to our Colombia subsidiary.

8. Commitments and Contingencies

In connection with our operations in Colombia, our foreign subsidiaries have obtained bonds for bidding on drilling contracts, performing under drilling contracts, and remitting customs and importation duties. We have guaranteed payments of $46.2 million relating to our performance under these bonds.

The Colombian government enacted a tax reform act which, among other things, adopted a one-time, net-worth tax for all Colombian entities, which was assessed on January 1, 2011 and is payable in eight semi-annual installments from 2011 through 2014. Based on our Colombian operations' net equity, measured on a Colombian tax basis as of January 1, 2011, our total net-worth tax obligation is approximately $7.3 million, which is not deductible for tax purposes. We recognized this tax obligation in full during the first quarter of 2011 in other expense in our condensed consolidated statement of operations. As of June 30, 2012, we have a remaining obligation of $4.8 million, which is recorded in other accrued expenses and other long-term liabilities on our condensed consolidated balance sheet.

Due to the nature of our business, we are, from time to time, involved in litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment-related disputes. Legal costs relating to these matters are expensed as incurred. In the opinion of our management, none of the pending litigation, disputes or claims against us will have a material adverse effect on our financial condition, results of operations or cash flow from operations.

9. Guarantor/Non-Guarantor Condensed Consolidated Financial Statements

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by our existing domestic subsidiaries, except for Pioneer Services Holdings, LLC, Pioneer Coiled Tubing Services, LLC, and certain of our future domestic subsidiaries. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture. In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes. As of June 30, 2012, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company.

As a result of the guarantee arrangements, we are presenting the following condensed consolidated balance sheets, statements of operations and statements of cash flows of the issuer, the guarantor subsidiaries and the non-guarantor subsidiaries.

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited, in thousands)

	June 30, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$20,768	$(3,665)	$3,277	$—	$20,380
Receivables, net of allowance	4	124,591	44,708	(1,810)	167,493
Intercompany receivable (payable)	(125,333)	145,911	(20,578)	—	—
Deferred income taxes	620	6,704	7,026	—	14,350
Inventory	—	5,187	8,024	—	13,211
Prepaid expenses and other current assets	1,197	9,294	2,842	—	13,333
Total current assets	(102,744)	288,022	45,299	(1,810)	228,767
Net property and equipment	2,301	807,952	129,942	(750)	939,445
Investment in subsidiaries	1,054,605	223,940	—	(1,278,545)	—
Intangible assets, net of amortization	59	16,707	31,439	—	48,205
Goodwill	—	—	41,683	—	41,683
Noncurrent deferred income taxes	41,608	—	1,242	(41,608)	1,242
Other long-term assets	10,611	1,440	15	—	12,066
Total assets	$1,006,440	$1,338,061	$249,620	$(1,322,713)	$1,271,408
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$1,092	$85,075	$9,022	—	$95,189
Current portion of long-term debt	—	850	21	—	871
Prepaid drilling contracts	—	2,726	1,345	—	4,071
Accrued expenses	13,381	44,420	10,763	(1,810)	66,754
Total current liabilities	14,473	133,071	21,151	(1,810)	166,885
Long-term debt, less current portion	453,170	—	120	—	453,290
Noncurrent deferred income taxes	—	145,902	1,395	(41,608)	105,689
Other long-term liabilities	110	4,483	3,014	—	7,607
Total liabilities	467,753	283,456	25,680	(43,418)	733,471
Total shareholders’ equity	538,687	1,054,605	223,940	(1,279,295)	537,937
Total liabilities and shareholders’ equity	$1,006,440	$1,338,061	$249,620	$(1,322,713)	$1,271,408

	December 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$91,932	$(13,879)	$8,144	$—	$86,197
Receivables, net of allowance	(2)	112,531	32,724	(19)	145,234
Intercompany receivable (payable)	(122,552)	131,585	(9,033)	—	—
Deferred income taxes	1,408	8,644	5,381	—	15,433
Inventory	—	4,533	6,651	—	11,184

Prepaid expenses and other current assets	285	6,304	4,975	—	11,564
Total current assets	(28,929)	249,718	48,842	(19)	269,612
Net property and equipment	1,605	675,679	117,422	(750)	793,956
Investment in subsidiaries	932,237	221,201	—	(1,153,438)	—
Intangible assets, net of amortization	171	18,829	33,680	—	52,680
Goodwill	—	—	41,683	—	41,683
Noncurrent deferred income taxes	30,835	—	735	(30,835)	735
Other long-term assets	11,949	2,124	15	—	14,088
Total assets	$947,868	$1,167,551	$242,377	$(1,185,042)	$1,172,754
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$1,090	$57,150	$8,200	$—	$66,440
Current portion of long-term debt	—	850	22	—	872
Prepaid drilling contracts	—	1,297	2,669	—	3,966
Accrued expenses	16,779	45,012	6,631	(20)	68,402
Total current liabilities	17,869	104,309	17,522	(20)	139,680
Long-term debt, less current portion	417,747	850	131	—	418,728
Noncurrent deferred income taxes	921	124,659	—	(30,835)	94,745
Other long-term liabilities	137	5,496	3,523	—	9,156
Total liabilities	436,674	235,314	21,176	(30,855)	662,309
Total shareholders' equity	511,194	932,237	221,201	(1,154,187)	510,445
Total liabilities and shareholders' equity	$947,868	$1,167,551	$242,377	$(1,185,042)	$1,172,754

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	Three months ended June 30, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$193,332	$36,492	$—	$229,824
Costs and expenses:					
Operating costs	—	116,644	27,670	—	144,314
Depreciation and amortization	292	33,800	5,897	—	39,989
General and administrative	5,552	14,339	2,512	(138)	22,265
Intercompany leasing	—	(1,215)	1,199	16	—
Bad debt (recovery) expense	—	(95)	39	—	(56)
Total costs and expenses	5,844	163,473	37,317	(122)	206,512
Income (loss) from operations	(5,844)	29,859	(825)	122	23,312
Other (expense) income:					
Equity in earnings of subsidiaries	17,970	(387)	—	(17,583)	—
Interest expense	(7,695)	43	2	—	(7,650)
Other	(72)	250	(36)	(122)	20
Total other expense	10,203	(94)	(34)	(17,705)	(7,630)
Income (loss) before income taxes	4,359	29,765	(859)	(17,583)	15,682
Income tax (expense) benefit	5,326	(11,795)	472	—	(5,997)
Net income (loss)	$9,685	$17,970	$(387)	$(17,583)	$9,685

	Three months ended June 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$142,043	$29,242	$—	$171,285
Costs and expenses:					
Operating costs	—	89,034	21,910	—	110,944
Depreciation and amortization	212	29,011	3,201	—	32,424
General and administrative	4,762	10,480	726	(108)	15,860
Intercompany leasing	—	(1,215)	1,215	—	—
Bad debt expense	—	139	—	—	139
Total costs and expenses	4,974	127,449	27,052	(108)	159,367
Income (loss) from operations	(4,974)	14,594	2,190	108	11,918
Other income (expense):					
Equity in earnings of subsidiaries	11,694	2,590	—	(14,284)	—
Interest expense	(7,932)	(56)	5	—	(7,983)
Other	(75)	215	722	(108)	754
Total other income (expense)	3,687	2,749	727	(14,392)	(7,229)
Income (loss) before income taxes	(1,287)	17,343	2,917	(14,284)	4,689
Income tax (expense) benefit	4,937	(5,649)	(327)	—	(1,039)
Net income (loss)	$3,650	$11,694	$2,590	$(14,284)	$3,650

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	Six months ended June 30, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:	$—	$384,174	$77,628	$—	$461,802
Costs and expenses:					
Operating costs	—	231,585	54,502	—	286,087
Depreciation and amortization	457	66,489	11,416	—	78,362
General and administrative	11,060	27,371	5,253	(276)	43,408
Intercompany leasing	—	(2,430)	2,430	—	—
Bad debt (recovery) expense	—	(275)	128	—	(147)
Impairment of equipment	—	1,032	—	—	1,032
Total costs and expenses	11,517	323,772	73,729	(276)	408,742
Income (loss) from operations	(11,517)	60,402	3,899	276	53,060
Other (expense) income:					
Equity in earnings of subsidiaries	41,520	4,261	—	(45,781)	—
Interest expense	(17,208)	3	—	—	(17,205)
Other	(140)	500	868	(276)	952
Total other expense	24,172	4,764	868	(46,057)	(16,253)
Income (loss) before income taxes	12,655	65,166	4,767	(45,781)	36,807
Income tax (expense) benefit	11,202	(23,646)	(506)	—	(12,950)
Net income (loss)	$23,857	$41,520	$4,261	$(45,781)	$23,857

	Six months ended June 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:	$—	$271,158	$53,476	$—	$324,634
Costs and expenses:					
Operating costs	—	170,912	40,769	—	211,681
Depreciation and amortization	487	58,129	6,064	—	64,680
General and administrative	8,893	20,370	1,334	(216)	30,381
Intercompany leasing	—	(2,430)	2,430	—	—
Bad debt expense	—	55	—	—	55
Total costs and expenses	9,380	247,036	50,597	(216)	306,797
Income (loss) from operations	(9,380)	24,122	2,879	216	17,837
Other income (expense):					
Equity in earnings of subsidiaries	12,501	(2,437)	—	(10,064)	—
Interest expense	(15,404)	(129)	11	—	(15,522)
Other	457	451	(6,455)	(216)	(5,763)
Total other income (expense)	(2,446)	(2,115)	(6,444)	(10,280)	(21,285)
Income (loss) before income taxes	(11,826)	22,007	(3,565)	(10,064)	(3,448)
Income tax (expense) benefit	9,441	(9,506)	1,128	—	1,063
Net income (loss)	$(2,385)	$12,501	$(2,437)	$(10,064)	$(2,385)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Six months ended June 30, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$(105,441)	$181,850	$15,289	$—	$91,698
Cash flows from investing activities:					
Purchases of property and equipment	(998)	(172,671)	(20,215)	—	(193,884)
Proceeds from sale of property and equipment	—	1,885	72	—	1,957
	(998)	(170,786)	(20,143)	—	(191,927)
Cash flows from financing activities:					
Debt repayments	—	(850)	(13)	—	(863)
Proceeds from issuance of debt	35,000	—	—	—	35,000
Debt issuance costs	(23)	—	—	—	(23)
Proceeds from exercise of options	655	—	—	—	655
Purchase of treasury stock	(357)	—	—	—	(357)
	35,275	(850)	(13)	—	34,412
Net increase (decrease) in cash and cash equivalents	(71,164)	10,214	(4,867)	—	(65,817)
Beginning cash and cash equivalents	91,932	(13,879)	8,144	—	86,197
Ending cash and cash equivalents	$20,768	$(3,665)	$3,277	$—	$20,380

	Six months ended June 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$(20,670)	$73,595	$686	$—	$53,611
Cash flows from investing activities:					
Acquisition of production services businesses	—	(2,000)	—	—	(2,000)
Purchases of property and equipment	(270)	(74,542)	(4,384)	—	(79,196)
Proceeds from sale of property and equipment	—	1,993	7	—	2,000
Proceeds from sale of auction rate securities	12,569	—	—	—	12,569
	12,299	(74,549)	(4,377)	—	(66,627)
Cash flows from financing activities:					
Debt repayments	(12,813)	(929)	—	—	(13,742)
Proceeds from issuance of debt	17,000	—	—	—	17,000
Debt issuance costs	(3,186)	—	—	—	(3,186)
Proceeds from exercise of options	2,091	—	—	—	2,091
Purchase of treasury stock	(352)	—	—	—	(352)
Excess tax benefit of stock option exercises	696	—	—	—	696
	3,436	(929)	—	—	2,507
Net decrease in cash and cash equivalents	(4,935)	(1,883)	(3,691)	—	(10,509)
Beginning cash and cash equivalents	15,737	(1,840)	8,114	—	22,011
Ending cash and cash equivalents	$10,802	$(3,723)	$4,423	$—	$11,502

17

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

Statements we make in the following discussion that express a belief, expectation or intention, as well as those that are not historical fact, are forward-looking statements that are subject to risks, uncertainties and assumptions. Our actual results, performance or achievements, or industry results, could differ materially from those we express in the following discussion as a result of a variety of factors, including general economic and business conditions and industry trends, levels and volatility of oil and gas prices, decisions about onshore exploration and development projects to be made by oil and gas exploration and production companies, risks associated with economic cycles and their impact on capital markets and liquidity, the continued demand for the drilling services or production services in the geographic areas where we operate, the highly competitive nature of our business, our future financial performance, including availability, terms and deployment of capital, future compliance with covenants under our senior secured revolving credit facility and our senior notes, the supply of marketable drilling rigs, well servicing rigs, coiled tubing and wireline units within the industry, the continued availability of drilling rig, well servicing rig, coiled tubing and wireline unit components, the continued availability of qualified personnel, the success or failure of our acquisition strategy, including our ability to finance acquisitions, manage growth and effectively integrate acquisitions, and changes in, or our failure or inability to comply with, governmental regulations, including those relating to the environment. We have discussed many of these factors in more detail elsewhere in this report and in our Annual Report on Form 10-K for the year ended December 31, 2011, including under the headings “Special Note Regarding Forward-Looking Statements” in the Introductory Note to Part I and “Risk Factors” in Item 1A. These factors are not necessarily all the important factors that could affect us. Unpredictable or unknown factors we have not discussed in this report or in our Annual Report on Form 10-K for the year ended December 31, 2011 could also have material adverse effects on actual results of matters that are the subject of our forward-looking statements. All forward-looking statements speak only as of the date on which they are made and we undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise. We advise our shareholders that they should (1) be aware that important factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements.

Company Overview

Pioneer Drilling Company was incorporated under the laws of the State of Texas in 1979 as the successor to a business that had been operating since 1968. Since September 1999, we have significantly expanded our drilling rig fleet through acquisitions and through the construction of rigs from new and used components. In March 2008, we significantly expanded our service offerings with the acquisition of two production services businesses, which provide well servicing, wireline services and fishing and rental services. We have continued to invest in the growth of all our service offerings through acquisitions and organic growth. On December 31, 2011, we acquired the coiled tubing services business of Go-Coil, L.L.C. ("Go-Coil") to expand our existing production services offerings.

On July 30, 2012, we changed our company name from "Pioneer Drilling Company" to "Pioneer Energy Services Corp." Our common stock will continue to trade on the New York Stock Exchange, but our ticker symbol has changed from "PDC" to "PES". Our company name change reinforces our strategy to expand our service offerings beyond drilling services, which has been our core, legacy business. Pioneer Energy Services provides drilling services and production services to independent and major oil and gas exploration and production companies throughout much of the onshore oil and gas producing regions of the United States and internationally in Colombia. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of a well site and enable us to meet multiple needs of our clients.

Business Segments

We currently conduct our operations through two operating segments: Drilling Services Segment and Production Services Segment. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 7, Segment Information, of the Notes to Condensed Consolidated Financial Statements, included in Part I, Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

- Drilling Services Segment—Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies with its fleet of 66 drilling rigs which are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	15
East Texas	3
West Texas	20
North Dakota	11
Utah	5
Appalachia	4
Colombia	8
	66

Drilling revenues and rig utilization have steadily improved since late 2009, primarily due to increased demand for drilling services in domestic shale plays and oil or liquid rich regions. We capitalized on this trend by moving drilling rigs in our fleet to these higher demand regions from lower demand regions. As a result, we closed our Oklahoma and North Texas drilling divisions during 2011 and established our West Texas drilling division in early 2011.

At June 30, 2012, we have 66 drilling rigs in our fleet. In 2011, we began construction, based on term contracts, on ten new-build AC drilling rigs that are fit for purpose for domestic shale plays. Construction has been completed for four of these new-build drilling rigs, three of which began operating under their term contracts in June and July 2012. We expect another four of the new-build drilling rigs to begin working by the end of 2012, with the remaining three during the first quarter of 2013. As of July 20, 2012, 54 drilling rigs are operating under drilling contracts, 45 of which are under term contracts, and one completed new-build drilling rig is under contract to begin working in the third quarter of 2012. We are actively marketing all our idle drilling rigs.

In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with clients. Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed.

- Production Services Segment—Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services, coiled tubing services, and fishing and rental services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. We provide our services to a diverse group of oil and gas exploration and production companies. The primary production services we offer are the following:

- Well Servicing. Existing and newly-drilled wells require a range of services to establish and maintain production over their useful lives. We use our well servicing rig fleet to provide these required services, including maintenance of existing wells, workover of existing wells, completion of newly-drilled wells, and plugging and abandonment of wells at the end of their useful lives. We have acquired 12 well servicing rigs during 2012, resulting in a total of 101 well servicing rigs in 12 divisions as of July 20, 2012. Our well servicing rig fleet consists of ninety 550 horsepower rigs, ten 600 horsepower rigs, and one 400 horsepower rig. All our well servicing rigs are currently operating or are being actively marketed. We plan to add another 7 well servicing rigs to our fleet during 2012.

- Wireline Services. In order for oil and gas exploration and production companies to better understand the reservoirs they are drilling or producing, they require logging services to accurately characterize reservoir rocks and fluids. When a producing well is completed, they also must perforate the production casing to establish a flow path between the reservoir and the wellbore. We use our fleet of wireline units to provide these important logging and perforating services. We provide both open and cased-hole logging services, including the latest pulsed-neutron technology. In addition, we provide services which allow oil and gas exploration and production companies to evaluate the integrity of wellbore casing, recover pipe, or install bridge plugs. As of July 20, 2012, we operate in 25 divisions with 117 wireline units and plan to add another three wireline units to our fleet during 2012.
- Coiled Tubing Services. Coiled tubing is an important element of the well servicing industry today that allows operators to continue production during service operations without shutting in the well, thereby reducing the risk of formation damage. Coiled tubing services involve the use of a continuous metal pipe spooled on a large reel for oil and natural gas well applications, such as wellbore clean-outs, nitrogen jet lifts, through-tubing fishing, formation stimulation utilizing acid, chemical treatments and fracturing. Coiled tubing is also used for a number of horizontal well applications such as milling temporary plugs between frac stages. Our coiled tubing business consists of seven onshore and four offshore coiled tubing units which are currently deployed in Texas, Louisiana and Oklahoma. We plan to add another two coiled tubing units to our fleet during 2012.
- Fishing and Rental Services. During drilling operations, oil and gas exploration and production companies frequently rent unique equipment such as power swivels, foam circulating units, blow-out preventers, air drilling equipment, pumps, tanks, pipe, tubing and fishing tools. We provide rental services out of four districts in Texas and Oklahoma. As of June 30, 2012 our fishing and rental tools have a gross book value of $15.6 million.

Pioneer Energy Services' corporate office is located at 1250 NE Loop 410, Suite 1000, San Antonio, Texas 78209. Our phone number is (210) 828-7689 and our website address is www.pioneeres.com. We make available free of charge though our website our Annual Reports on our Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission (SEC). Information on our website is not incorporated into this report or otherwise made part of this report.

Market Conditions in Our Industry

Demand for oilfield services offered by our industry is a function of our clients’ willingness to make operating expenditures and capital expenditures to explore for, develop and produce hydrocarbons, which in turn is affected by current and expected levels of oil and natural gas prices.

From 2004 through 2008, domestic exploration and production spending increased as oil and natural gas prices increased. From late 2008 and into late 2009, there was substantial volatility and a decline in oil and natural gas prices due to the downturn in the global economic environment. In response, our clients curtailed their drilling programs and reduced their production activities, particularly in natural gas producing regions, which resulted in a decrease in demand and revenue rates for certain of our drilling rigs and production services equipment. Additionally, there was uncertainty in the capital markets and access to financing was limited. These conditions adversely affected our business environment.

With increasing oil and natural gas prices during 2010, exploration and production companies modestly increased their exploration and production spending for 2010 and industry rig utilization and revenue rates improved, particularly in oil-producing regions and in certain shale regions. Increased natural gas production in the U.S. shale regions continues to depress natural gas prices, but oil prices continued to increase during 2011, resulting in continued increases in exploration and production spending during 2011 as compared to 2010. As a result, we experienced continued increases in industry rig utilization and revenue rates during 2011 as compared to 2010. There have been modest increases in exploration and production spending during the first half of 2012, which has resulted in modest increases in industry equipment utilization and revenue rates when compared to 2011. However, oil prices have begun to decline during the first half of 2012 and natural gas prices have remained at low levels. If this downward trend in oil and natural gas prices continues for the remainder of 2012, then industry equipment utilization and revenue rates

could decrease domestically and in Colombia. Since June 2012, we have experienced a modest decrease in the demand for drilling rigs in certain regions.
For additional information concerning the effects of the volatility in oil and gas prices and uncertainty in capital markets, see Item 1A – "Risk Factors" in Part I of our Annual Report on Form 10-K for the year ended December 31, 2011.

On July 20, 2012, the spot price for West Texas Intermediate crude oil was $91.44, the spot price for Henry Hub natural gas was $3.03 and the Baker Hughes U.S. land rig count was 1,866, compared to 1,861 on July 22, 2011. The average spot prices of West Texas Intermediate crude oil and Henry Hub natural gas, the average domestic land rig count per Baker Hughes, and the average domestic well servicing rig count for the month of June for each of the last five years were:

	Averages for the month of June,				
	2012	2011	2010	2009	2008
Oil (West Texas Intermediate)	$83.22	$95.92	$75.27	$69.80	$137.06
Natural Gas (Henry Hub)	$2.43	$4.51	$4.83	$3.74	$12.78
U.S. Land Rig Count	1,903	1,813	1,499	842	1,810
U.S. Well Servicing Rig Count	2,139	2,069	1,857	1,648	2,554

Since late 2009, increases primarily in oil prices have caused increases in exploration and production spending and the corresponding increases in drilling and well servicing activities are reflected by increases in the U.S. land rig counts and the U.S. well servicing rig counts in 2010 and 2011.

Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or operating expenditure.

Capital expenditures by oil and gas exploration and production companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of years. As such, capital expenditure economics often require the use of commodity price forecasts which may prove inaccurate in the amount of time required to plan and execute a capital expenditure project (such as the drilling of a deep well). When commodity prices are depressed for long periods of time, capital expenditure projects are routinely deferred until prices return to an acceptable level.

In contrast, both mandatory and discretionary operating expenditures are more stable than capital expenditures for exploration. Mandatory operating expenditure projects involve activities that cannot be avoided in the short term, such as regulatory compliance, safety, contractual obligations and certain projects to maintain the well and related infrastructure in operating condition. Discretionary operating expenditure projects may not be critical to the short-term viability of a lease or field, but these projects are less sensitive to commodity price volatility as compared to capital expenditures for exploration. Discretionary operating expenditure work is evaluated according to a simple short-term payout criterion which is far less dependent on commodity price forecasts.

Because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by exploration and production companies for the maintenance of existing wells are relatively stable and predictable. In contrast, capital expenditures by exploration and production companies for exploration and drilling are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices.

Strategy

In past years, our strategy was to become a premier land drilling and production services company through steady and disciplined growth. We executed this strategy by acquiring and building a high quality drilling rig fleet and production services business that operate in active drilling markets in the United States and Colombia. Our long-term strategy is to maintain and leverage our position as a leading land drilling and production services company, continue to expand our relationships with existing clients, expand our client base in the areas in which we currently operate and further enhance our geographic diversification through selective international expansion. The key elements of this long-term strategy include:

- Further Strengthen our Competitive Position in the Most Attractive Domestic Markets. Shale plays and non-shale oil or liquid rich environments are increasingly important to domestic hydrocarbon production and not all drilling rigs are capable of successfully drilling in these unconventional opportunities. We are currently operating in unconventional areas in the Bakken, Marcellus and Eagle Ford shales and Permian and Uintah Basins, and expect all of our new-build drilling rigs to be operating in the shale plays by early 2013. We also intend to continue adding capacity to our wireline, coiled tubing, and well servicing product offerings, which are well positioned to capitalize on increased shale development.

- Increase our Exposure to Oil-Driven Drilling Activity. We have intentionally increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions and actively seeking contracts with oil-focused producers. As of July 20, 2012, approximately 94% of our working drilling rigs and 80% of our production services assets are operating on wells that are targeting or producing oil or liquids rich natural gas. We believe that our flexible rig fleet and production services assets allow us to target opportunities focused on both natural gas and oil.
- Maintain Our International Presence. In early 2007, we announced our intention to selectively expand internationally and began a relationship with Ecopetrol S.A. in Colombia after a comprehensive review of international opportunities wherein we determined that Colombia offered an attractive mix of favorable business conditions, political stability, and a long-term commitment to expanding national oil and gas production. We continue to evaluate international opportunities to expand our drilling and production services, with our primary focus in Colombia.
- Continue Growth with Select Capital Deployment. We intend to invest in the growth of our business by continuing to strategically upgrade our existing assets, selectively engaging in new-build opportunities, and potentially making selective acquisitions. Our capital investment decisions are determined by an analysis of the projected return on capital employed, which is based on the terms of secured contracts whenever possible, and the investment must be consistent with our strategic objectives. In 2011, based on term contracts, we began construction on ten new-build AC drilling rigs that are fit for purpose for domestic shale plays. Construction has been completed for three of these new-build drilling rigs which began operating under their term contracts in June and July 2012. We expect another four new-build drilling rigs to begin working by the end of 2012, with the remaining three during the first quarter of 2013. On December 31, 2011, we acquired the coiled tubing services business of Go-Coil to expand our existing production services offerings. We are further growing our production services fleets by adding a total of 17 wireline units, 19 well servicing rigs and three coiled tubing units during 2012.

Liquidity and Capital Resources

Sources of Capital Resources

Our principal liquidity requirements have been for working capital needs, capital expenditures and selective acquisitions. Our principal sources of liquidity consist of cash and cash equivalents (which equaled $20.4 million as of June 30, 2012), cash generated from operations, and the unused portion of our senior secured revolving credit facility (the “Revolving Credit Facility”).

In May 2012, we filed a registration statement that permits us to sell equity or debt in one or more offerings up to a total dollar amount of $300 million. At July 20, 2012, the entire $300 million under the shelf registration statement is available for equity or debt offerings. In the future, we may consider equity or debt offerings, as appropriate, to meet our liquidity needs.

On March 11, 2010, we issued $250 million of senior notes with a coupon interest rate of 9.875% that are due in 2018 (the "2010 Senior Notes"). We received $234.8 million of net proceeds from the issuance of the 2010 Senior Notes that were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility. On November 21, 2011, we issued an additional $175 million of senior notes (the "2011 Senior Notes") with the same terms and conditions as the 2010 Senior Notes. We received $172.7 million of net proceeds from the issuance of the 2011 Senior Notes, a portion of which were used to fund the acquisition of Go-Coil in December 2011.

Our Revolving Credit Facility provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of $250 million, all of which matures on June 30, 2016. As of July 20, 2012, we had $35.0 million outstanding under our Revolving Credit Facility and $9.0 million in committed letters of credit, which resulted in borrowing availability of $206.0 million under our Revolving Credit Facility. There are no limitations on our ability to access the full borrowing availability under the Revolving Credit Facility other than maintaining compliance with the covenants in the Revolving Credit Facility. Additional information regarding these covenants is provided in the Debt Requirements section below. Borrowings under the Revolving Credit Facility are available for selective acquisitions, working capital and other general corporate purposes.

We currently expect that cash and cash equivalents, cash generated from operations and available borrowings under our Revolving Credit Facility are adequate to cover our liquidity requirements for at least the next 12 months.

Uses of Capital Resources

During the six months ended June 30, 2012, we had $221.4 million of additions to our property and equipment. Currently, we expect to spend approximately $325 million to $345 million on capital expenditures during 2012. We expect the total capital expenditures for 2012 will be allocated approximately 70% for our Drilling Services Segment and approximately 30% for our Production Services Segment. Our planned capital expenditures for the year ending December 31, 2012 include well servicing, coiled tubing and wireline fleet additions, partial construction of new-build AC drilling rigs, upgrades to certain drilling rigs and routine capital expenditures. Actual capital expenditures may vary depending on the level of new-build and other expansion opportunities that meet our strategic and return on capital criteria. We expect to fund the remaining capital expenditures from operating cash flow in excess of our working capital requirements and from borrowings under our Revolving Credit Facility.

Working Capital

Our working capital was $61.9 million at June 30, 2012, compared to $129.9 million at December 31, 2011. Our current ratio, which we calculate by dividing current assets by current liabilities, was 1.4 at June 30, 2012 compared to 1.9 at December 31, 2011.

Our operations have historically generated cash flows sufficient to meet our requirements for debt service and normal capital expenditures. However, our short term working capital needs could increase during periods when higher percentages of our drilling contracts are turnkey and footage contracts and when new-build rig construction projects are in progress.

The changes in the components of our working capital were as follows (amounts in thousands):

	June 30, 2012	December 31, 2011	Change
Cash and cash equivalents	$20,380	$86,197	$(65,817)
Receivables:			
Trade, net of allowance for doubtful accounts	128,950	106,084	22,866
Unbilled receivables	31,267	31,512	(245)
Insurance recoveries	5,693	5,470	223
Income taxes	1,583	2,168	(585)
Deferred income taxes	14,350	15,433	(1,083)
Inventory	13,211	11,184	2,027
Prepaid expenses and other current assets	13,333	11,564	1,769
Current assets	228,767	269,612	(40,845)
Accounts payable	95,189	66,440	28,749
Current portion of long-term debt	871	872	(1)
Prepaid drilling contracts	4,071	3,966	105
Accrued expenses:			
Payroll and related employee costs	24,965	29,057	(4,092)
Insurance premiums and deductibles	9,741	10,583	(842)
Insurance claims and settlements	5,580	5,470	110
Interest	12,269	12,283	(14)
Other	14,199	11,009	3,190
Current liabilities	166,885	139,680	27,205
Working capital	$61,882	$129,932	$(68,050)

The decrease in cash and cash equivalents during the six months ended June 30, 2012 is primarily due to $193.9 million used for purchases of property and equipment, partially offset by $91.7 million of cash provided by operating activities and $34.1 million provided by net proceeds from the issuance of debt.

The increases in our trade and unbilled receivables as of June 30, 2012 as compared to December 31, 2011 were primarily due to the increase in revenues of $26.2 million, or 13%, for the quarter ended June 30, 2012 as compared to the quarter ended December 31, 2011, and due to the timing of the billing and collection cycles for long-term drilling contracts in Colombia.

The decrease in current deferred income tax assets as of June 30, 2012 as compared to December 31, 2011 is primarily due to a decrease in our annual bonus accrual, which reflects six months of bonus compensation at June 30, 2012 as compared to a full year of bonus compensation at December 31, 2011. We record a current deferred income tax asset associated with the annual bonus accrual since these bonuses are paid after year end once operating results are finalized.

The increase in our inventory as of June 30, 2012 as compared to December 31, 2011 is primarily due to an increase in the coiled tubing inventory as well as for the expansion of our wireline operations during the first half of 2012.

The increase in prepaid expenses and other assets as of June 30, 2012 as compared to December 31, 2011 is primarily due to an increase in deferred mobilization costs for domestic drilling rigs that moved between drilling divisions. The increase is partially offset by a decrease in prepaid insurance costs because most of the insurance premiums are paid in late October of each year, and therefore we had amortization of eight months of these October premiums at June 30, 2012, as compared to two months at December 31, 2011.

The increase in accounts payable is primarily due to the increase in operating costs of $15.9 million, or 12%, for the quarter ended June 30, 2012 as compared to the quarter ended December 31, 2011, and due to a $27.5 million increase in our accruals for capital expenditures as of June 30, 2012, as compared to December 31, 2011.

The decrease in accrued payroll and employee related costs as of June 30, 2012 as compared to December 31, 2011 is primarily due to the payment of our 2011 annual bonuses in February 2012, which were fully accrued for as of December 31, 2011.

The increase in other accrued expenses as of June 30, 2012 as compared to December 31, 2011 is primarily due to an increase in our sales tax accrual primarily relating to the construction of our new-build drilling rigs, partially offset by a decrease in property tax accruals since most property taxes are paid annually during the first quarter.

Long-term Debt and Other Contractual Obligations

The following table includes all our contractual obligations at June 30, 2012 (amounts in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
Long-term debt	$460,991	$871	$51	$35,069	$425,000
Interest on long-term debt	256,116	43,106	86,049	84,992	41,969
Purchase commitments	83,161	83,161	—	—	—
Operating leases	17,919	5,075	6,716	2,705	3,423
Restricted cash obligation	650	650	—	—	—
Total	$818,837	$132,863	$92,816	$122,766	$470,392

At June 30, 2012, long-term debt primarily consists of $425.0 million face amount outstanding under our Senior Notes, $35.0 million outstanding under our Revolving Credit Facility and $0.9 million outstanding under other notes payable to certain employees that are former shareholders of previously acquired production services businesses. We expect to use the availability under the Revolving Credit Facility to fund our working capital needs, capital expenditures, or selective acquisitions, as necessary. The $35.0 million outstanding under our Revolving Credit Facility is due at maturity on June 30, 2016. However, we may make principal payments to reduce the outstanding balance prior to maturity when cash and working capital is sufficient. The $425.0 million face amount outstanding under our Senior Notes will mature on March 15, 2018. Our Senior Notes have a carrying value of $418.2 million as of June 30, 2012, which represents the $425.0 million face value net of the $8.4 million of original issue discount and $1.6 million of original issue premium, net of amortization, based on the effective interest method. Our other notes payable have final maturity dates in March and April 2013.

24

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 3.0% interest rate that was in effect at July 20, 2012, and (2) the outstanding balance of $35.0 million at June 30, 2012 to be paid at maturity on June 30, 2016. Interest payment obligations on our Senior Notes are calculated based on the coupon interest rate of 9.875% due semi-annually in arrears on March 15 and September 15 of each year. Interest payment obligations on our subordinated notes payable are based on interest rates ranging from 6% to 14%, with annual payments of principal and interest through maturity.
Purchase commitments primarily relate to new-build drilling rigs, equipment upgrades and purchases of other new equipment. The total estimated cost for the ten new-build drilling rigs is approximately $220 million to $240 million, of which $173.1 million has already been incurred and $35.9 million is reflected in the purchase commitments included in the table above.
Operating leases consist of lease agreements for office space, operating facilities, equipment and personal property.
As of June 30, 2012, we had restricted cash in the amount of $0.7 million held in an escrow account to be used for a future payment due March 2013 in connection with the acquisition of Competition.
Debt Requirements
The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and letter of credit exposure. There are no limitations on our ability to access the $250 million borrowing capacity other than maintaining compliance with the covenants under the Revolving Credit Facility. At June 30, 2012, we were in compliance with our financial covenants. Our total consolidated leverage ratio was 1.9 to 1.0, our senior consolidated leverage ratio was 0.2 to 1.0, and our interest coverage ratio was 8.0 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum total consolidated leverage ratio that cannot exceed 4.00 to 1.00;
- A maximum senior consolidated leverage ratio, which excludes unsecured and subordinated debt, that cannot exceed 2.50 to 1.00;
- A minimum interest coverage ratio that cannot be less than 2.50 to 1.00; and
- If our senior consolidated leverage ratio is greater than 2.00 to 1.00 at the end of any fiscal quarter, our minimum asset coverage ratio cannot be less than 1.00 to 1.00.

The Revolving Credit Facility does not restrict capital expenditures as long as (a) no event of default exists under the Revolving Credit Facility or would result from such capital expenditures, (b) after giving effect to such capital expenditures there is availability under the Revolving Credit Facility equal to or greater than $25 million and (c) the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is less than 2.00 to 1.00. If the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is equal to or greater than 2.00 to 1.00, then capital expenditures are limited to $100 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $30 million.
At June 30, 2012, our senior consolidated leverage ratio was not greater than 2.00 to 1.00 and therefore, we were not subject to the capital expenditure threshold restrictions listed above.
The Revolving Credit Facility has additional restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. In addition, the Revolving Credit Facility contains customary events of default, including without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness in excess of specified amounts, certain events of bankruptcy and insolvency, judgment defaults in excess of specified amounts, failure of any guaranty or security document supporting the credit agreement and change of control.
Our obligations under the Revolving Credit Facility are secured by substantially all of our domestic assets (including equity interests in Pioneer Global Holdings, Inc. and 65% of the outstanding equity interests of any first-tier foreign subsidiaries owned by Pioneer Global Holdings, Inc., but excluding any equity interest in, and any assets of, Pioneer

Services Holdings, LLC and Pioneer Coiled Tubing Services, LLC) and are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Borrowings under the Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.

In addition to the financial covenants under our Revolving Credit Facility, the Indenture Agreement for our Senior Notes contains certain restrictions generally on our ability to:

- pay dividends on stock;
- repurchase stock or redeem subordinated debt or make other restricted payments;
- incur, assume or guarantee additional indebtedness or issue disqualified stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- pay dividends, engage in loans, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person;
- enter into transactions with affiliates; and
- enter into new lines of business.

Upon the occurrence of a change of control, holders of the Senior Notes will have the right to require us to purchase all or a portion of the Senior Notes at a price equal to 101% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase. Under certain circumstances in connection with asset dispositions, we will be required to use the excess proceeds of asset dispositions to make an offer to purchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase.

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by our existing domestic subsidiaries, except for Pioneer Services Holdings, LLC and Pioneer Coiled Tubing Services, LLC, and by certain of our future domestic subsidiaries. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture. In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes.

Our Senior Notes are not subject to any sinking fund requirements. As of June 30, 2012, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company, and we were in compliance with all covenants pertaining to our Senior Notes.

Results of Operations
Statements of Operations Analysis
The following table provides information about our operations for the three and six months ended June 30, 2012 and 2011 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Drilling Services Segment:				
Revenues	$119,048	$106,523	$243,352	$206,279
Operating costs	78,631	73,190	159,708	140,699
Drilling Services Segment margin	$40,417	$33,333	$83,644	$65,580
Average number of drilling rigs	62.5	71.0	63.2	71.0
Utilization rate	89 %	69 %	88 %	67 %
Revenue days	5,032	4,442	10,096	8,593
Average revenues per day	$23,658	$23,981	$24,104	$24,005
Average operating costs per day	15,626	16,477	15,819	16,374
Drilling Services Segment margin per day	$8,032	$7,504	$8,285	$7,631
Production Services Segment:				
Revenues	$110,776	$64,762	$218,450	$118,355
Operating costs	65,683	37,754	126,379	70,982
Production Services Segment margin	$45,093	$27,008	$92,071	$47,373
Combined:				
Revenues	$229,824	$171,285	$461,802	$324,634
Operating costs	144,314	110,944	286,087	211,681
Combined margin	$85,510	$60,341	$175,715	$112,953
Adjusted EBITDA	$63,321	$45,096	$133,406	$76,754

Drilling Services Segment margin represents contract drilling revenues less contract drilling operating costs. Production Services Segment margin represents production services revenue less production services operating costs. We believe that Drilling Services Segment margin and Production Services Segment margin are useful measures for evaluating financial performance, although they are not measures of financial performance under U.S. Generally Accepted Accounting Principles (GAAP). However, Drilling Services Segment margin and Production Services Segment margin are common measures of operating performance used by investors, financial analysts, rating agencies and Pioneer’s management. A reconciliation of Drilling Services Segment margin and Production Services Segment margin to net income (loss), as reported is included in the table below. Drilling Services Segment margin and Production Services Segment margin as presented may not be comparable to other similarly titled measures reported by other companies.

Adjusted EBITDA is a financial measure that is not in accordance with GAAP, and should not be considered (i) in isolation of, or as a substitute for, net earnings (loss), (ii) as an indication of operating performance or cash flows from operating activities or (iii) as a measure of liquidity. In addition, Adjusted EBITDA does not represent funds available for discretionary use. We define Adjusted EBITDA as earnings (loss) before interest income (expense), taxes, depreciation, amortization and any impairments. We use this measure, together with our GAAP financial metrics, to assess our financial performance and evaluate our overall progress towards meeting our long-term financial objectives. We believe that this non-GAAP financial measure is useful to investors and analysts in allowing for greater transparency of our operating performance and makes it easier to compare our results with those of other companies within our industry. Adjusted EBITDA, as we calculate it, may not be comparable to Adjusted EBITDA measures reported by other companies. A reconciliation of Adjusted EBITDA to net income (loss) is set forth in the following table.

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	(amounts in thousands)			
Reconciliation of combined margin and Adjusted EBITDA to net income (loss):				
Combined margin	$85,510	$60,341	$175,715	$112,953
General and administrative	(22,265)	(15,860)	(43,408)	(30,381)
Bad debt recovery (expense)	56	(139)	147	(55)
Other income (expense)	20	754	952	(5,763)
Adjusted EBITDA	63,321	45,096	133,406	76,754
Depreciation and amortization	(39,989)	(32,424)	(78,362)	(64,680)
Impairment of equipment	—	—	(1,032)	—
Interest expense	(7,650)	(7,983)	(17,205)	(15,522)
Income tax (expense) benefit	(5,997)	(1,039)	(12,950)	1,063
Net income (loss)	$9,685	$3,650	$23,857	$(2,385)

Our Drilling Services Segment experienced increases in its revenues and operating costs due to higher demand for our drilling services in 2012 as compared to 2011, as our industry continues to recover from the downturn that bottomed in late 2009. Revenues increased as a result of increasing oil prices and rig utilization and improved revenue rates particularly in oil-producing regions and in certain shale regions.

Our Drilling Services Segment's revenues increased by $12.5 million, or 12%, and $37.1 million, or 18%, for the three and six months ended June 30, 2012, respectively, as compared to the corresponding periods in 2011, primarily due to an increase in drilling rig utilization. With the increase in demand for our drilling services during 2012, our revenue days increased by 13% and 17% for the three and six months ended June 30, 2012, respectively, when compared to the corresponding periods in 2011. The increase in our drilling rig utilization rate was also partially a result of our decision to dispose of seven drilling rigs in September 2011 and another two drilling rigs in March 2012. Our average drilling revenues per day remained flat despite an increase in daywork rates for our domestic drilling contracts, which were offset by the impact of less revenue days for our Colombian operations and fewer turnkey contracts, which have higher average drilling revenues per day.

Our Drilling Services Segment's operating costs increased by $5.4 million, or 7%, and $19.0 million, or 14%, for the three and six months ended June 30, 2012, respectively, as compared to the corresponding periods in 2011, primarily due to the increase in utilization and partially offset by the decrease in our operating costs per day. Our operating costs per day decreased by 5%, or $851 per day and 3% or $555 per day, for the three and six months ended June 30, 2012, respectively, as compared to the corresponding periods in 2011. Our operating costs per day decreased in 2012 despite an increase in operating costs per day for our domestic daywork drilling contracts, which were more than offset by the impact of less revenue days for our Colombian operations and turnkey contracts, which have higher operating costs per day.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain. As demand for drilling rigs decreases, daywork rates move down and we may switch to performing more turnkey drilling contracts to maintain higher utilization rates and improve our Drilling Services Segment's margins. Turnkey drilling contracts also result in higher average revenues per day and higher average operating costs per day when compared to daywork drilling contracts. We completed one and six turnkey drilling contracts during the three and six months ended June 30, 2012, as compared to four and ten turnkey drilling contracts completed during the corresponding periods in 2011.

The following table provides percentages of our drilling revenues by drilling contract type for the three and six months ended June 30, 2012 and 2011:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Daywork Contracts	100 %	98 %	96 %	95 %
Turnkey Contracts	— %	2 %	4 %	5 %

Our Production Services Segment's revenues increased by $46.0 million, or 71%, and $100.1 million, or 85%, for the three and six months ended June 30, 2012, respectively, as compared to the corresponding periods in 2011, while operating costs increased $27.9 million, or 74% and $55.4 million, or 78%. The increases in revenues and operating costs are primarily due to the expansion of our operations through fleet additions and the acquisition of Go-Coil on December 31, 2011. Higher demand for our other production services, which resulted in higher utilization rates and higher revenue rates charged for these services during the three and six months ended June 30, 2012, has also increased both our Production Services Segment's revenues and operating costs for the three and six months ended June 30, 2012, as compared to the corresponding periods in 2011.

Our general and administrative expense increased by approximately $6.4 million, or 40%, and $13.0 million, or 43% for the three and six months ended June 30, 2012, respectively, as compared to the corresponding periods in 2011. The increase is primarily due to increases in payroll and compensation related expenses. As a result of increasing demand for our services and the expansion of our operations through fleet additions and the acquisition of Go-Coil on December 31, 2011, payroll and compensation related expenses increased as we added employees and accrued for increased incentive compensation.

Our other expense for the six months ended June 30, 2011 primarily related to the $7.3 million net-worth tax expense for our Colombian operations which was assessed on January 1, 2011. The increase was partially offset by $0.5 million of income recognized for the ARPS's Call Option during the six months ended June 30, 2011.

Our depreciation and amortization expenses increased by $7.6 million and $13.7 million for the three and six months ended June 30, 2012, respectively, as compared to the corresponding periods in 2011. This increase resulted primarily from the expansion of our operations through the acquisition of Go-Coil on December 31, 2011, capital expenditures for fleet additions that began operating in 2012 and upgrades to certain drilling rigs to meet the needs of our clients and obtain new contracts.

During the six months ended June 30, 2012, we recorded impairment charges of $1.0 million in association with our decision to retire two mechanical drilling rigs, with most of their components to be used as spare parts, and to retire two wireline units and certain wireline equipment.

Our interest expense increased for the six months ended June 30, 2012, as compared to the corresponding period in 2011, primarily due to the issuance of our Senior Notes in November 2011. The issuance of our Senior Notes in November 2011 increased our overall debt balance in 2012. The overall increase in interest expense was partially offset by $6.0 million of capitalized interest during the six months ended June 30, 2012, associated with the capital expenditures for upgrades to our drilling rig fleet and for our new-build drilling rigs.

Our effective income tax rate for the three and six months ended June 30, 2012 differs from the federal statutory rate in the United States of 35% primarily due to a lower effective tax rate in foreign jurisdictions, state income taxes, the effect of foreign translation and other permanent differences.

Inflation

Wage rates for our operations personnel are impacted by inflationary pressures when the demand for drilling and production services increases and the availability of personnel is scarce. Beginning in late 2009, increasing rig counts have resulted in a tightening of labor markets, and therefore we had wage rate increases of approximately 10% across multiple divisions in January 2012.

Costs for rig repairs and maintenance, rig upgrades and new rig construction are also impacted by inflationary pressures when the demand for drilling services increases. We experienced an increase in these costs of approximately 10% during 2011, and we estimate that we will experience similar increases in 2012.

Off-Balance Sheet Arrangements

We do not currently have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Revenue and cost recognition—Our Drilling Services Segment earns revenues by drilling oil and gas wells for our clients under daywork, turnkey or footage contracts, which usually provide for the drilling of a single well. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey and footage contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. Individual contracts are usually completed in less than 60 days. The risks to us under a turnkey contract and, to a lesser extent, under footage contracts, are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors' services, supplies, cost escalations and personnel operations.

Our management has determined that it is appropriate to use the percentage-of-completion method to recognize revenue on our turnkey and footage contracts. Although our turnkey and footage contracts do not have express terms that provide us with rights to receive payment for the work that we perform prior to drilling wells to the agreed-on depth, we use this method because, as provided in applicable accounting literature, we believe we achieve a continuous sale for our work-in-progress and believe, under applicable state law, we ultimately could recover the fair value of our work-in-progress even in the event we were unable to drill to the agreed-on depth in breach of the applicable contract. However, in the event we were unable to drill to the agreed-on depth in breach of the contract, ultimate recovery of that value would be subject to negotiations with the client and the possibility of litigation.

If a client defaults on its payment obligation to us under a turnkey or footage contract, we would need to rely on applicable law to enforce our lien rights, because our turnkey and footage contracts do not expressly grant to us a security interest in the work we have completed under the contract and we have no ownership rights in the work-in-progress or completed drilling work, except any rights arising under the applicable lien statute on foreclosure. If we were unable to drill to the agreed-on depth in breach of the contract, we also would need to rely on equitable remedies outside of the contract available in applicable courts to recover the fair value of our work-in-progress under a turnkey or footage contract.

We accrue estimated contract costs on turnkey and footage contracts for each day of work completed based on our estimate of the total costs to complete the contract divided by our estimate of the number of days to complete the contract. Contract costs include labor, materials, supplies, repairs and maintenance, operating overhead allocations and allocations of depreciation and amortization expense. In addition, the occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey and footage contracts could have a material adverse effect on our financial position and results of operations. Therefore, our actual results for a contract could differ significantly if our cost estimates for that contract are later revised from our original cost estimates for a contract in progress at the end of a reporting period which was not completed prior to the release of our financial statements.

With most drilling contracts, we receive payments contractually designated for the mobilization of rigs and other equipment. Payments received, and costs incurred for the mobilization services are deferred and recognized on a straight line basis over the related contract term. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements that we receive for out-of-pocket expenses are recorded as revenue and the out-of-pocket expenses for which they relate are recorded as operating costs.

Our Production Services Segment earns revenues for well servicing, wireline services, coiled tubing services and fishing and rental services pursuant to master services agreements based on purchase orders, contracts or other arrangements with the client that include fixed or determinable prices. Production service revenue is recognized when the service has been rendered and collectability is reasonably assured.

The asset "unbilled receivables" represents revenues we have recognized in excess of amounts billed on drilling contracts and for production services completed but not yet invoiced. The assets "prepaid expenses and other current assets" and "other long-term assets" include the current and long-term portions of deferred mobilization costs for certain drilling contracts. The liabilities "prepaid drilling contracts" and "other long-term liabilities" include the current and long-term portions of deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized. As of June 30, 2012, we had $4.1 million and $7.0 million of current deferred mobilization revenues and costs, respectively. Amortization of deferred mobilization revenues was $2.5 million and $2.6 million for the six months ended June 30, 2012 and 2011, respectively.

Long-lived assets and intangible assets—We evaluate for potential impairment of long-lived assets and intangible assets subject to amortization when indicators of impairment are present. Circumstances that could indicate a potential impairment include significant adverse changes in industry trends, economic climate, legal factors, and an adverse action or assessment by a regulator. More specifically, significant adverse changes in industry trends include significant declines in revenue rates, utilization rates, oil and natural gas market prices and industry rig counts for drilling rigs and well servicing rigs. In performing the impairment evaluation, we estimate the future undiscounted net cash flows relating to long-lived assets and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, our long-lived assets and intangible assets are grouped at the reporting unit level which is one level below the operating segment level. For our Drilling Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for individual drilling rig assets. If the sum of the estimated future undiscounted net cash flows is less than the carrying amount of the long-lived assets and intangible assets for these asset grouping levels, then we would recognize an impairment charge. The amount of an impairment charge would be measured as the difference between the carrying amount and the fair value of these assets. The assumptions used in the impairment evaluation for long-lived assets and intangible assets are inherently uncertain and require management judgment.

Goodwill—Goodwill results from business acquisitions and represents the excess of acquisition costs over the fair value of the net assets acquired. We perform a qualitative assessment of goodwill annually as of December 31 or more frequently if events or changes in circumstances indicate that the asset might be impaired. Circumstances that could indicate a potential impairment include a significant adverse change in the economic or business climate, a significant adverse change in legal factors, an adverse action or assessment by a regulator, unanticipated competition, loss of key personnel and the likelihood that a reporting unit or significant portion of a reporting unit will be sold or otherwise disposed of. These circumstances could lead to our net book value exceeding our market capitalization which is another indicator of a potential impairment in goodwill.

If our qualitative assessment of goodwill indicates a possible impairment, we test for goodwill impairment using a two-step process. First, the fair value of each reporting unit with goodwill is compared to its carrying value to determine whether an indication of impairment exists. Second, if impairment is indicated, then the fair value of the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination on the impairment test date. The amount of impairment for goodwill is measured as the excess of the carrying value of the reporting unit over its fair value. The assumptions used in estimating fair values of reporting units and performing the goodwill impairment test are inherently uncertain and require management judgment.

When estimating fair values of a reporting unit for our goodwill impairment test, we use a combination of an income approach and a market approach which incorporates both management’s views and those of the market. The income approach provides an estimated fair value based on each reporting unit’s anticipated cash flows that are discounted using a weighted average cost of capital rate. The market approach provides an estimated fair value based on our market capitalization that is computed using the prior 30-day average market price of our common stock and the number of shares outstanding as of the impairment test date.

The estimated fair values computed using the income approach and the market approach are then equally weighted and combined into a single fair value. The primary assumptions used in the income approach are estimated cash flows and weighted average cost of capital. Estimated cash flows are primarily based on projected revenues, operating costs and capital expenditures and are discounted based on comparable industry average rates for weighted average cost of capital. The primary assumption used in the market approach is the allocation of total market capitalization to each reporting unit, which is based on projected EBITDA percentages for each reporting unit, and control premiums, which are based on comparable industry averages. To ensure the reasonableness of the estimated fair values of our reporting units, we perform a reconciliation of our total market capitalization to the total estimated fair value of all our reporting units. The assumptions used in estimating fair values of reporting units and performing the goodwill impairment test are inherently uncertain and require management judgment.

We have goodwill of $41.7 million as of June 30, 2012. All of this goodwill was recorded in connection with the acquisition of the production services business from Go-Coil on December 31, 2011, as described in Note 2, Acquisitions. As a result, the goodwill has been allocated to the coiled tubing services reporting unit within our Production Services Segment operating segment.

Deferred taxes—We provide deferred taxes for the basis differences in our property and equipment between financial reporting and tax reporting purposes and other costs such as compensation, net operating loss carryforwards, employee benefit and other accrued liabilities which are deducted in different periods for financial reporting and tax reporting purposes. For property and equipment, basis differences arise from differences in depreciation periods and methods and the value of assets acquired in a business acquisition where we acquire an entity rather than just its assets. For financial reporting purposes, we depreciate the various components of our drilling rigs, well servicing rigs, wireline units and coiled tubing units over 2 to 25 years and refurbishments over 3 to 5 years, while federal income tax rules require that we depreciate drilling rigs, well servicing rigs, wireline units and coiled tubing units over 5 years. Therefore, in the first 5 years of our ownership of a drilling rig, well servicing rig, wireline unit or coiled tubing units, our tax depreciation exceeds our financial reporting depreciation, resulting in our providing deferred taxes on this depreciation difference. After 5 years, financial reporting depreciation exceeds tax depreciation, and the deferred tax liability begins to reverse.

Accounting estimates—We consider the recognition of revenues and costs on turnkey and footage contracts to be critical accounting estimates. On these types of contracts, we are required to estimate the number of days needed for us to complete the contract and our total cost to complete the contract. Our actual costs could substantially exceed our estimated costs if we encounter problems such as lost circulation, stuck drill pipe or an underground blowout on contracts still in progress subsequent to the release of the financial statements. We receive payment under turnkey and footage contracts when we deliver to our client a well completed to the depth specified in the contract, unless the client authorizes us to drill to a more shallow depth. Since 1995, we have completed all our turnkey or footage contracts. Although our initial cost estimates for turnkey and footage contracts do not include cost estimates for risks such as stuck drill pipe or loss of circulation, we believe that our experienced management team, our knowledge of geologic formations in our areas of operations, the condition of our drilling equipment and our experienced crews have previously enabled us to make reasonable cost estimates and complete contracts according to our drilling plan. While we do bear the risk of loss for cost overruns and other events that are not specifically provided for in our initial cost estimates, our pricing of turnkey and footage contracts takes such risks into consideration. We are more likely to encounter losses on turnkey and footage contracts in periods in which revenue rates are lower for all types of contracts. During periods of reduced demand for drilling rigs, our overall profitability on turnkey and footage contracts has historically exceeded our profitability on daywork contracts. When we encounter, during the course of our drilling operations, conditions unforeseen in the preparation of our original cost estimate, we increase our cost estimate to complete the contract. If we anticipate a loss on a contract in progress at the end of a reporting period due to a change in our cost estimate, we accrue the entire amount of the estimated loss, including all costs that are included in our revised estimated cost to complete that contract, in our consolidated statement of operations for that reporting period. We did not experience a loss on any of the turnkey contracts completed during the six months ended June 30, 2012.

Revenues and costs during a reporting period could be affected for contracts in progress at the end of a reporting period which have not been completed before our financial statements for that period are released. We had no turnkey contracts in progress at June 30, 2012. Our unbilled receivables totaled $31.3 million at June 30, 2012, including unbilled receivables related to $27.1 million of the revenue recognized but not yet billed on daywork drilling contracts in progress at June 30, 2012 and $4.1 million related to unbilled receivables for our Production Services Segment.

We estimate an allowance for doubtful accounts based on the creditworthiness of our clients as well as general economic conditions. We evaluate the creditworthiness of our clients based on commercial credit reports, trade references, bank references, financial information, production information and any past experience we have with the client. Consequently, any change in those factors could affect our estimate of our allowance for doubtful accounts. In some instances, we require new clients to establish escrow accounts or make prepayments. We typically invoice our clients at 15-day intervals during the performance of daywork contracts and upon completion of the daywork contract. Turnkey and footage contracts are invoiced upon completion of the contract. Our typical contract provides for payment of invoices in 10 to 30 days. We generally do not extend payment terms beyond 30 days and have not extended payment terms beyond 90 days for any of our contracts in the last three fiscal years. We had an allowance for doubtful accounts of $1.3 million at June 30, 2012.

Our determination of the useful lives of our depreciable assets, which directly affects our determination of depreciation expense and deferred taxes is also a critical accounting estimate. A decrease in the useful life of our property and equipment would increase depreciation expense and reduce deferred taxes. We provide for depreciation of our drilling, production, transportation and other equipment on a straight-line method over useful lives that we have estimated and that range from 2 to 25 years. We record the same depreciation expense whether a drilling rig, well servicing rig, wireline unit or coiled tubing unit is idle or working. Our estimates of the useful lives of our drilling, production, transportation and other equipment are based on our more than 40 years of experience in the oilfield services industry with similar equipment.

As of June 30, 2012, we had a $1.2 million deferred tax asset related to the $3.3 million impairment of our ARPSs which represents a capital loss for tax treatment purposes. We can recognize a tax benefit associated with this impairment to the extent of capital gains we expect to earn in future periods. During the year ended December 31, 2011, we recorded a valuation allowance to fully offset our deferred tax asset relating to this capital loss since we believe capital gains are not likely in future periods.

As of June 30, 2012, we had $40.3 million of deferred tax assets related to foreign and domestic net operating loss and AMT credit carryforwards available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we only recognize a tax benefit to the extent of taxable income that we expect to earn in the jurisdiction in future periods. We estimate that our operations will result in taxable income in excess of our net operating losses and we expect to apply the net operating losses against the current year taxable income and taxable income that we have estimated in future periods.

Our accrued insurance premiums and deductibles as of June 30, 2012 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $2.4 million and our workers' compensation, general liability and auto liability insurance of approximately $6.6 million. We have stop-loss coverage of $150,000 per occurrence under our health insurance and a deductible of $500,000 per occurrence under our workers' compensation insurance. We have a deductible of $250,000 per occurrence under both our general liability insurance and auto liability insurance. We accrue for these costs as claims are incurred using an actuarial calculation that is based on industry and our company's historical claim development data, and we accrue the costs of administrative services associated with claims processing.

Our stock-based compensation expense includes estimates for certain of our long-term incentive compensation plans which have performance-based award components dependent upon our performance over a set performance period, as compared to the performance of a pre-defined peer group. The accruals for these awards include estimates which affect our stock-based compensation expense, employee related accruals and equity. The accruals are adjusted based on actual achievement levels at the end of the pre-determined performance periods.

Recently Issued Accounting Standards

Fair Value Measurement. In May 2011, the FASB issued ASU No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This update clarifies existing guidance about how fair value should be applied where it already is required or permitted and provides wording changes that align this standard with International Financial Reporting Standards (IFRS). We are required to apply this guidance prospectively beginning with our first quarterly filing in 2012. The adoption of this new guidance has not had an impact on our financial position or results of operations.

Comprehensive Income. In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income. This update increases the prominence of other comprehensive income in financial statements, eliminating the option of presenting other comprehensive income in the statement of changes in equity, and instead, requiring the components of net income and comprehensive income to be presented in either one or two consecutive financial statements. We are required to comply with this guidance prospectively beginning with our first quarterly filing in 2012. We have not recognized any other comprehensive income during either of the six month periods ended June 30, 2012 or 2011. The adoption of this new guidance has not had an impact on our financial position or results of operations.

In December 2011, the FASB issued ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05. This update delays the effective date of the requirement to present reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements.

Intangibles–Goodwill and Other. In September 2011, the FASB issued ASU No. 2011-08, Intangibles–Goodwill and Other (Topic 350): Testing Goodwill for Impairment. This update allows entities testing goodwill for impairment the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step goodwill impairment test). If entities determine, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step impairment test would be required. The amendments are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this new guidance has not had an impact on our financial position or results of operations.

Other Regulation

The Colombian government enacted a tax reform act which, among other things, adopted a one-time, net-worth tax for all Colombian entities, which was assessed on January 1, 2011 and is payable in eight semi-annual installments from 2011 through 2014.

Based on our Colombian operations' net equity, measured on a Colombian tax basis as of January 1, 2011, our total net-worth tax obligation is approximately $7.3 million, which is not deductible for tax purposes. We recognized this tax obligation in full during the first quarter of 2011 in other expense in our condensed consolidated statement of operations. As of June 30, 2012, we have a remaining obligation of $4.8 million, which is recorded in other accrued expenses and other long-term liabilities on our condensed consolidated balance sheet.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

We are subject to interest rate market risk on our variable rate debt. As of June 30, 2012, we had $35.0 million outstanding under our Revolving Credit Facility, which is our only variable rate debt. The impact of a 1% increase in interest rates on this amount of debt would have resulted in an increase in interest expense of approximately $90,000 and a decrease in net income of approximately $60,000 during the three months ended June 30, 2012.

Foreign Currency Risk

While the U.S. dollar is the functional currency for reporting purposes for our Colombian operations, we enter into transactions denominated in Colombian pesos. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period. As a result, Colombian Peso denominated transactions are affected by changes in exchange rates. We generally accept the exposure to exchange rate movements without using derivative financial instruments to manage this risk. Therefore, both positive and negative movements in the Colombian Peso currency exchange rate against the U.S. dollar has and will continue to affect the reported amount of revenues, expenses, profit, and assets and liabilities in the Company's consolidated financial statements.

The impact of currency rate changes on our Colombian Peso denominated transactions and balances resulted in foreign currency gains of $0.9 million for the six months ended June 30, 2012.

Item 4. Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2012, to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the three months ended June 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment-related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us will have a material adverse effect on our financial condition or results of operations.

Item 1A. Risk Factors

Not applicable.

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

We did not make any unregistered sales of equity securities during the quarter ended June 30, 2012.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share (2)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
April 1 - April 30	154	$8.01	—	—
May 1 - May 31	7,760	$7.91	—	—
June 1 - June 30	238	$7.49	—	—
Total	8,152	$7.90	—	—

(1) The shares indicated consist of shares of our common stock tendered by employees to the Company during the three months ended June 30, 2012, to satisfy the employees' tax withholding obligations in connection with the exercise of nonqualified stock options and issuance of restricted stock, which we repurchased based on the fair market value on the date the relevant transaction occurred.

(2) The calculation of the average price paid per share does not give effect to any fees, commissions or other costs associated with the repurchase of such shares.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this report or incorporated by reference herein:

Exhibit Number		Description
3.1*	-	Restated Articles of Incorporation of Pioneer Energy Services Corp. (Form 8-K date July 30, 2012 (File No. 1-8182, Exhibit 3.1)).
3.2*	-	Amended and Restated Bylaws of Pioneer Energy Services Corp. (Form 8-K dated July 30, 2012 (File No. 1-8182, Exhibit 3.2)).
4.1**	-	Form of Certificate representing Common Stock of Pioneer Energy Services Corp.
4.2*	-	Indenture, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 12, 2010, (File No. 1-8182, Exhibit 4.1)).
4.3*	-	Registration Rights Agreement, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated March 12, 2010, (File No. 1-8182, Exhibit 4.2)).
4.4*	-	First Supplemental Indenture, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated November 21, 2011, (File No. 1-8182, Exhibit 4.2)).
4.5*	-	Registration Rights Agreement, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated November 21, 2011, (File No. 1-8182, Exhibit 4.3)).
31.1**	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2**	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32.1#	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2#	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101#	-	The following financial statements from Pioneer Energy Services Corp.'s Form 10-Q for the quarter ended June 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets, (ii) Condensed Consolidated Statements of Operations, (iii) Condensed Consolidated Statements of Cash Flows, and (iv) Notes to Condensed Consolidated Financial Statements.

Information is furnished and not filed and is not incorporated by reference in any registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under those sections.

* Incorporated by reference to the filing indicated.
** Filed herewith.
\# Furnished herewith.

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.

PIONEER ENERGY SERVICES CORP.

/s/ Lorne E. Phillips
Lorne E. Phillips
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Duly Authorized Officer)
Dated: August 7, 2012

Index to Exhibits

Exhibit Number		Description
3.1*	-	Restated Articles of Incorporation of Pioneer Energy Services Corp. (Form 8-K date July 30, 2012 (File No. 1-8182, Exhibit 3.1)).
3.2*	-	Amended and Restated Bylaws of Pioneer Energy Services Corp. (Form 8-K dated July 30, 2012 (File No. 1-8182, Exhibit 3.2)).
4.1**	-	Form of Certificate representing Common Stock of Pioneer Energy Services Corp.
4.2*	-	Indenture, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 12, 2010, (File No. 1-8182, Exhibit 4.1)).
4.3*	-	Registration Rights Agreement, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated March 12, 2010, (File No. 1-8182, Exhibit 4.2)).
4.4*	-	First Supplemental Indenture, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated November 21, 2011, (File No. 1-8182, Exhibit 4.2)).
4.5*	-	Registration Rights Agreement, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated November 21, 2011, (File No. 1-8182, Exhibit 4.3)).
31.1**	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2**	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32.1#	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2#	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101#	-	The following financial statements from Pioneer Energy Services Corp.'s Form 10-Q for the quarter ended June 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets, (ii) Condensed Consolidated Statements of Operations, (iii) Condensed Consolidated Statements of Cash Flows, and (iv) Notes to Condensed Consolidated Financial Statements. Information is furnished and not filed and is not incorporated by reference in any registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed

for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under those sections.

* Incorporated by reference to the filing indicated.
** Filed herewith.
\# Furnished herewith.