PIONEER ENERGY SERVICES CORP
Form 10-Q
October 30, 2013

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 September 30, 2013

or

o 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: (855) 884-0575

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	o	Accelerated filer	x
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 October 25, 2013, there were 62,459,486 shares of common stock, par value $0.10 per share, of the registrant outstanding.

PART 1. FINANCIAL INFORMATION
Item 1. Financial Statements
PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2013 (Unaudited)	December 31, 2012 (Audited)
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$17,085	$23,733
Receivables:		
Trade, net of allowance for doubtful accounts	124,836	115,070
Unbilled receivables	45,048	35,140
Insurance recoveries	8,774	6,518
Income taxes and other	3,431	2,116
Deferred income taxes	12,597	11,058
Inventory	12,732	12,111
Prepaid expenses and other current assets	5,709	13,040
Total current assets	230,212	218,786
Property and equipment, at cost	1,707,706	1,698,517
Less accumulated depreciation	748,214	684,177
Net property and equipment	959,492	1,014,340
Intangible assets, net of accumulated amortization of $30.8 million and $24.4 million at September 30, 2013 and December 31, 2012, respectively	34,326	43,843
Goodwill	—	41,683
Noncurrent deferred income taxes	1,335	5,519
Assets held for sale	6,718	—
Other long-term assets	19,518	15,605
Total assets	$1,251,601	$1,339,776
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$47,642	$83,823
Current portion of long-term debt	23	872
Deferred revenues	906	3,880
Accrued expenses:		
Payroll and related employee costs	25,989	27,991
Insurance premiums and deductibles	10,707	9,708
Insurance claims and settlements	8,665	6,348
Interest	1,820	12,343
Other	10,601	11,585
Total current liabilities	106,353	156,550
Long-term debt, less current portion	534,421	518,725
Noncurrent deferred income taxes	85,278	108,838
Other long-term liabilities	6,677	7,983
Total liabilities	732,729	792,096
Commitments and contingencies (Note 7)		

Shareholders' equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock $.10 par value; 100,000,000 shares authorized; 62,436,990 and 62,032,517 shares outstanding at September 30, 2013 and December 31, 2012, respectively	6,266	6,217
Additional paid-in capital	454,742	449,554
Treasury stock, at cost; 218,883 and 134,612 shares at September 30, 2013 and December 31, 2012, respectively	(1,892)	(1,264)
Accumulated earnings	59,756	93,173
Total shareholders' equity	518,872	547,680
Total liabilities and shareholders' equity	$1,251,601	$1,339,776

See accompanying notes to condensed consolidated financial statements.

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per share data)			
Revenues:				
Drilling services	$131,033	$125,662	$402,357	$369,014
Production services	112,946	104,111	319,646	322,561
Total revenues	243,979	229,773	722,003	691,575
Costs and expenses:				
Drilling services	89,350	88,188	267,630	247,896
Production services	71,910	65,395	202,662	191,774
Depreciation and amortization	47,414	42,067	141,047	120,429
General and administrative	23,896	21,269	70,872	64,677
Bad debt expense (recovery)	35	(368)	453	(515)
Impairment charges	9,504	—	54,292	1,032
Total costs and expenses	242,109	216,551	736,956	625,293
Income (loss) from operations	1,870	13,222	(14,953)	66,282
Other (expense) income:				
Interest expense	(12,324)	(9,453)	(36,117)	(26,658)
Other	610	307	(1,460)	1,259
Total other expense	(11,714)	(9,146)	(37,577)	(25,399)
Income (loss) before income taxes	(9,844)	4,076	(52,530)	40,883
Income tax benefit (expense)	3,614	(1,461)	19,113	(14,411)
Net income (loss)	$(6,230)	$2,615	$(33,417)	$26,472
Income (loss) per common share—Basic	$(0.10)	$0.04	$(0.54)	$0.43
Income (loss) per common share—Diluted	$(0.10)	$0.04	$(0.54)	$0.42
Weighted average number of shares outstanding—Basic	62,325	61,881	62,158	61,743
Weighted average number of shares outstanding—Diluted	62,325	62,825	62,158	62,695

See accompanying notes to condensed consolidated financial statements.

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

	Nine months ended September 30,	
	2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(33,417)	$26,472
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	141,047	120,429
Allowance for doubtful accounts	534	2
Gain on dispositions of property and equipment	(865)	(1,230)
Stock-based compensation expense	4,692	5,541
Amortization of debt issuance costs, discount and premium	2,309	2,224
Impairment charges	54,292	1,032
Deferred income taxes	(21,153)	12,270
Change in other long-term assets	(5,554)	(1,964)
Change in other long-term liabilities	(1,306)	(2,168)
Changes in current assets and liabilities:		
Receivables	(21,353)	(27,471)
Inventory	(620)	(993)
Prepaid expenses and other current assets	7,330	1,756
Accounts payable	(379)	4,769
Deferred revenues	(2,973)	(1,086)
Accrued expenses	(12,509)	(10,271)
Net cash provided by operating activities	110,075	129,312
Cash flows from investing activities:		
Purchases of property and equipment	(137,945)	(291,051)
Proceeds from sale of property and equipment	6,898	2,433
Net cash used in investing activities	(131,047)	(288,618)
Cash flows from financing activities:		
Debt repayments	(25,868)	(869)
Proceeds from issuance of debt	40,000	80,000
Debt issuance costs	(13)	(58)
Proceeds from exercise of options	833	684
Purchase of treasury stock	(628)	(357)
Net cash provided by financing activities	14,324	79,400
Net decrease in cash and cash equivalents	(6,648)	(79,906)
Beginning cash and cash equivalents	23,733	86,197
Ending cash and cash equivalents	$17,085	$6,291
Supplementary disclosure:		
Interest paid	$45,273	$43,349
Income tax paid	$2,508	$88

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

Pioneer Energy Services provides drilling services and production services to a diverse group of independent and large 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. We also provide coiled tubing and wireline services offshore in the Gulf of Mexico.

Our Drilling Services Segment provides contract land drilling services with its fleet of 62 drilling rigs which are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
East Texas	1
West Texas	18
North Dakota	11
Utah	7
Appalachia	4
Colombia	8
	62

In early 2011, we began construction of ten new-build AC drilling rigs that are fit for purpose for domestic shale plays, based on term contracts. We deployed seven of these new-build drilling rigs during 2012, and deployed the final three in early 2013. All of our new-build drilling rigs are currently operating in shale or unconventional plays under long-term drilling contracts.

During the second quarter of 2013, we sold two mechanical drilling rigs that were previously idle in our East Texas division, for which we recognized an associated gain of approximately $0.8 million. In September 2013, we decided to sell eight of our mechanical drilling rigs, for which we recognized an impairment charge of $9.2 million dollars during the third quarter. All eight drilling rigs are classified as held for sale at September 30, 2013 and were sold in late October 2013.

As of September 30, 2013, 56 of our 62 drilling rigs are earning revenues under drilling contracts, 42 of which are under term contracts. All except one of our drilling rigs in Colombia are currently under contract, six of which are working under term contracts that expire at the end of 2013. We are currently in negotiations to renew the contracts for our rigs in Colombia and we are actively marketing all of 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 existing or potential 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 September 30, 2013, we have a fleet of 109 well servicing rigs consisting of ninety-nine 550 horsepower rigs and ten 600 horsepower rigs, all of which are currently operating or are being actively marketed. We currently provide wireline services and coiled tubing services with a fleet of 116 wireline units and 13 coiled tubing units, and we provide rental services with a gross book value of $17.2 million in fishing and rental tools.

Basis of Presentation

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. 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, 2012.

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 determination of depreciation and amortization expense, our estimates of fair value for impairment evaluations, our estimate of deferred taxes, our estimate of the liability relating to the self-insurance portion of our health and workers' compensation insurance, and our estimate of compensation related accruals.

In preparing the accompanying unaudited condensed consolidated financial statements, we have reviewed events that have occurred after September 30, 2013, through the filing of this Form 10-Q, for inclusion as necessary.

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. Spot contracts generally 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 September 30, 2013, we have 42 drilling rigs operating under term contracts, which if not renewed at the end of their terms, will expire as follows:

		Term Contract Expiration by Period				
	Total Term Contracts	Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years	2 to 4 Years
United States	36	22	3	5	—	6
Colombia	6	6	—	—	—	—
	42	28	3	5	—	6

Unbilled Accounts Receivable

The asset "unbilled receivables" represents revenues we have recognized in excess of amounts billed on drilling contracts and production services completed but not yet invoiced. We typically invoice our clients at 15-day intervals during the performance of daywork drilling contracts and upon completion of the daywork contract. Turnkey and footage drilling contracts are invoiced upon completion of the contract.

Our unbilled receivables totaled $45.0 million at September 30, 2013, of which $0.7 million related to turnkey drilling contract revenues, $39.4 million represented revenue recognized but not yet billed on daywork drilling contracts in progress at September 30, 2013 and $4.9 million related to unbilled receivables for our Production Services Segment.

Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets include items such as insurance, rent deposits and fees. We routinely expense these items in the normal course of business over the periods these expenses benefit. Prepaid expenses and other current assets also include the current portion of deferred mobilization costs for certain drilling contracts that are recognized on a straight-line basis over the contract term.

Property and Equipment

As of September 30, 2013 and December 31, 2012, we had incurred $21.3 million and $134.9 million, respectively, in construction costs for ongoing projects. The balance at December 31, 2012 primarily related to our new-build drilling rigs. During the nine months ended September 30, 2013 and 2012, we capitalized $0.9 million and $8.4 million, respectively, of interest costs incurred during the construction periods of new-build drilling rigs and other drilling equipment.

We recorded gains on disposition of our property and equipment of $0.9 million and $1.2 million for the nine months ended September 30, 2013 and 2012, respectively, in our drilling and production services costs and expenses. During the second quarter of 2013, we sold two mechanical drilling rigs that were previously idle in our East Texas division, for which we recognized an associated gain of approximately $0.8 million. Additionally, during the third quarter of 2013, we disposed of two wireline units and other wireline equipment.

We recorded impairment charges on our property and equipment of $9.5 million and $1.0 million for the nine months ended September 30, 2013 and 2012, respectively. During the third quarter of 2013, we decided to place eight of our mechanical drilling rigs as held for sale, and we recognized an impairment charge of $9.2 million to reduce the carrying value of these assets to their estimated fair value, based on their sales price. The sales of all eight drilling rigs were completed in late October 2013 and we did not incur any additional gain or loss upon the sale of these rigs. We also recorded an impairment charge of $0.3 million during the third quarter of 2013 in association with our decision to sell certain production services equipment. In March 2012, we retired two mechanical drilling rigs, with most of their components to be used as spare parts, as well as two wireline units and other wireline equipment, and recognized an associated impairment charge of $1.0 million.

We evaluate for potential impairment of long-lived tangible 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 an impairment evaluation, we estimate the future undiscounted net cash flows from the use and eventual disposition of long-lived tangible and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for the individual reporting units (well servicing, wireline, coiled tubing and fishing and rental services). 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 asset group, then we would determine the fair value of the asset group. 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 are inherently uncertain and require management judgment.

In September 2013, we evaluated the drilling rigs in our fleet and decided to place eight of our mechanical drilling rigs as held for sale and recognized an impairment charge to reduce the carrying value of these assets to their estimated fair value, which was based on their sales price. The decision to sell these drilling rigs was primarily due to a decrease in demand for non-top drive mechanical rigs that drill vertical oil and gas wells. Our remaining drilling rig fleet includes mechanical rigs that are currently working, but which may have reduced utilization if demand for vertical drilling continues to soften. We performed an impairment evaluation on the remaining drilling rigs in our fleet which are similar to those that we decided to sell. In order to estimate our future undiscounted cash flows from the use and eventual disposition of these assets, we incorporated probabilities of selling these rigs in the near term, versus working them through the end of their remaining useful lives. Our analysis led us to conclude that no impairment exists as of September 30, 2013 for the remaining similar drilling rigs. If the demand for vertical drilling continues to soften and these remaining mechanical rigs become idle for an extended amount of time, then the probability of a near term sale may increase, which would likely result in an impairment charge, based on the current market value of these drilling rigs. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions.

Intangible Assets

Substantially all of our intangible assets were recorded in connection with the acquisitions of production services businesses and are subject to amortization. We evaluate for potential impairment of long-lived tangible 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 an impairment evaluation, we estimate the future undiscounted net cash flows from the use and eventual disposition of long-lived tangible and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for the individual reporting units (well servicing, wireline, coiled tubing and fishing and rental services). If the sum of the estimated future undiscounted net cash flows is less than the carrying amount of the asset group, then we would determine the fair value of the asset group. 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 are inherently uncertain and require management judgment.

Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our long-lived tangible and intangible assets as of June 30, 2013. We determined that the sum of the estimated future undiscounted net cash flows for our coiled tubing services reporting unit was less than the carrying amount at June 30, 2013. We then performed a valuation of the assets which resulted in a non-cash impairment charge of $3.1 million to reduce our intangible asset carrying value of client relationships. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain coiled tubing markets where we operate and a decline in our projected cash flows for the coiled tubing reporting unit.

The most significant inputs used in our impairment analysis include the projected utilization and pricing of our coiled tubing services, which are classified as Level 3 inputs as defined by ASC Topic 820, Fair Value Measurements and Disclosures. An increase of 1% in either the utilization or pricing assumptions would have resulted in a decrease to our impairment charge for our long-lived intangible assets of approximately $1 million. Similarly, a decrease of 1% in either of these assumptions would have led to an approximate $1 million increase to our impairment charge. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating fair values and performing the impairment test are inherently uncertain and require management judgment.

Our impairment analysis did not result in any impairment charges to our coiled tubing tangible long-lived assets, substantially all of which was related to the 13 coiled tubing units. As discussed further below, we also recorded a non-cash impairment charge to reduce the carrying value of goodwill to zero.

Goodwill

Goodwill results from business acquisitions and represents the excess of acquisition costs over the fair value of the net assets acquired. In connection with the acquisition of the production services business from Go-Coil, we recorded $41.7 million of goodwill at December 31, 2011, all of which was allocated to the coiled tubing services reporting unit within our Production Services Segment.

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. In addition, these circumstances could lead to our net book value exceeding our market capitalization which is another indicator of a potential impairment of 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.

When estimating fair values of a reporting unit for our goodwill impairment test, we use an income approach which provides an estimated fair value based on the reporting unit's anticipated cash flows that are discounted using a weighted average cost of capital rate. 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 at a rate that is based on our weighted average cost of capital and estimated industry average rates for cost of capital. To ensure the reasonableness of the estimated fair value of our reporting units, we consider current industry market multiples and we perform a reconciliation of our total market capitalization to the total estimated fair value of all our reporting units.

Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our goodwill as of June 30, 2013. We determined that the fair value of our coiled tubing services reporting unit was less than its carrying value, including goodwill, and therefore, we performed the second step of the goodwill impairment test which led us to conclude that there would be no remaining implied fair value attributable to goodwill. Accordingly, we recorded a non-cash impairment charge of $41.7 million to reduce the carrying value of our goodwill to zero. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain coiled tubing markets where we operate and a decline in our projected cash flows for the coiled tubing reporting unit.

The most significant inputs used in our impairment analysis include the projected utilization and pricing of our coiled tubing services and the weighted average cost of capital (discount rate) used in order to calculate the discounted cash flows for the reporting unit. These inputs are classified as Level 3 inputs as defined by ASC Topic 820, Fair Value Measurements and Disclosures. We assumed a 13% discount rate to estimate the fair value of the coiled tubing services reporting unit. A decrease in this assumption of 5% would have resulted in a decrease to our goodwill impairment charge of approximately $3.5 million. An increase of 1% in either the utilization or pricing assumptions would have resulted in a decrease to our goodwill impairment charge of approximately $2 million or $3 million, respectively. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating fair values of reporting units and performing the goodwill impairment test are inherently uncertain and require management judgment.

Other Long-Term Assets

Other long-term assets consist of cash deposits related to the deductibles on our workers' compensation insurance policies, the long-term portion of deferred mobilization costs, debt issuance costs, net of amortization, and noncurrent prepaid taxes in Colombia which are creditable against future income taxes.

Other Current Liabilities

Our other accrued expenses include accruals for items such as property tax, sales tax, professional and other fees. We routinely expense these items in the normal course of business over the periods these expenses benefit. Our other accrued expenses also consist of the current portion of the Colombian net equity tax and the current portion of deferred mobilization revenues for certain drilling contracts that are recognized on a straight-line basis over the contract term.

Other Long-Term Liabilities

Our other long-term liabilities consist of the noncurrent portion of deferred mobilization revenues, liabilities associated with our long-term compensation plans, the noncurrent portion of the Colombia net equity tax and other deferred liabilities.

Reclassifications

Certain amounts in the financial statements for the prior years have been reclassified to conform to the current year's presentation.

2. Long-Term Debt

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

	September 30, 2013	December 31, 2012
Senior secured revolving credit facility	$115,000	$100,000
Senior notes	419,332	418,617
Other notes payable	112	980
	534,444	519,597
Less current portion	(23)	(872)
	$534,421	$518,725

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 currently in effect 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 are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Effective October 1, 2012, Pioneer Coiled Tubing Services, LLC (formerly Go-Coil, L.L.C.) was added as a subsidiary guarantor under the Revolving Credit Facility. Borrowings under the Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.

As of September 30, 2013, we had $115.0 million outstanding under our Revolving Credit Facility and $8.9 million in committed letters of credit, which resulted in borrowing availability of $126.1 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 September 30, 2013, we were in compliance with our financial covenants under the Revolving Credit Facility. Our total consolidated leverage ratio was 2.2 to 1.0, our senior consolidated leverage ratio was 0.5 to 1.0, and our interest coverage ratio was 5.5 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 September 30, 2013, 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.

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 September 30, 2013 with a total carrying value of $419.3 million, which represents the $425.0 million total face value net of the $7.0 million unamortized portion of original issue discount and $1.3 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.

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 September 30, 2013. 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. Effective October 1, 2012, Pioneer Coiled Tubing Services, LLC (formerly Go-Coil, L.L.C.) was added as a subsidiary guarantor under the Indenture. (See Note 8, Guarantor/Non-Guarantor Condensed Consolidated Financial Statements.)

Other Notes Payable

Our other debt 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 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 \$8.0 million and \$9.6 million as of September 30, 2013 and December 31, 2012, respectively. We recognized \$1.6 million and \$1.6 million of associated amortization during the nine months ended September 30, 2013 and 2012, respectively.

3. 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 September 30, 2013 and December 31, 2012, our financial instruments consist primarily of cash, trade and other receivables, trade payables, and long-term debt. The carrying value of cash, trade and other receivables and trade payables are considered to be representative of their respective fair values due to the short-term nature of these instruments.

The fair value of our long-term debt 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 is 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 September 30, 2013 and December 31, 2012 (amounts in thousands):

	September 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	$534,444	$575,365	$519,597	$565,257

4. Earnings Per Common Share

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Basic				
Net income (loss)	$(6,230)	$2,615	$(33,417)	$26,472
Weighted-average shares	62,325	61,881	62,158	61,743
Income (loss) per share	$(0.10)	$0.04	$(0.54)	$0.43
Diluted				
Net income (loss)	$(6,230)	$2,615	$(33,417)	$26,472
Weighted average shares:				
Outstanding	62,325	61,881	62,158	61,743
Diluted effect of stock options, restricted stock, and restricted stock unit awards	—	944	—	952
	62,325	62,825	62,158	62,695
Income (loss) per share	$(0.10)	$0.04	$(0.54)	$0.42

Potentially dilutive stock options, restricted stock and restricted stock unit awards representing a total of 5,510,520 and 5,467,291 shares of common stock for the three and nine months ended September 30, 2013, respectively, and 4,225,796 and 4,275,623 for the three and nine months ended September 30, 2012, respectively, were excluded from the computation of diluted weighted average shares outstanding due to their antidilutive effect.

5. Equity Transactions and Stock-Based Compensation Plans

Stock-based Compensation Plans

We grant stock option and restricted stock awards with vesting based on time of service conditions. We also 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.

The following table summarizes the compensation expense recognized for stock option, restricted stock and restricted stock unit awards during the three and nine months ended September 30, 2013 and 2012 (amounts in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Stock option awards	$412	$669	$1,359	$2,277
Restricted stock awards	157	133	420	556
Restricted stock unit awards	1,059	1,069	2,913	2,708
	$1,628	$1,871	$4,692	$5,541

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 option pricing model. There were no stock options granted during the three months ended September 30, 2013 or 2012. The following table summarizes the assumptions used in the Black-Scholes option pricing model based on a weighted-average calculation for the stock options granted during the nine months ended September 30, 2013 and 2012:

	Nine months ended September 30,	
	2013	2012
Expected volatility	66 %	70 %
Risk-free interest rates	1.0 %	0.8 %
Expected life in years	5.53	5.12
Options granted	220,656	530,156
Grant-date fair value	$4.36	$5.02

The assumptions used in the Black-Scholes option pricing model 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.

During the three and nine months ended September 30, 2013, 11,600 and 174,467 stock options were exercised at a weighted-average exercise price of $3.84 and $4.77, respectively. During the three and nine months ended September 30, 2012, 6,750 and 170,016 stock options were exercised at a weighted-average exercise price of $4.27 and $4.02, 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

Historically, we have generally granted 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. However, beginning in 2013, we began granting restricted stock awards with a vesting period of one year. 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. We did not grant any restricted stock awards during the three months ended September 30, 2013 or 2012. During the nine months ended September 30, 2013 and 2012, we granted 61,248 and 49,748 shares of restricted stock awards, with a weighted-average grant-date fair value of $7.57 and $8.04, respectively.

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.

There were no restricted stock unit awards granted during the three months ended September 30, 2013 or 2012. The following table summarizes the number and weighted-average grant-date fair value of the restricted stock unit awards granted during the nine months ended September 30, 2013 and 2012:

	Nine months ended September 30,	
	2013	2012
Time-based RSUs:		
Time-based RSUs granted	406,027	356,813
Weighted-average grant-date fair value	$ 7.59	$ 8.21
Performance-based RSUs:		
Performance-based RSUs granted	346,731	221,495
Weighted-average grant-date fair value	$ 8.34	$ 9.85

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.

Our performance-based RSUs generally cliff vest after 39 months from the date of grant and 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. The number of shares of common stock awarded will be based upon the Company’s achievement in certain performance conditions, as compared to a predefined peer group, over the performance period, generally three years. 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. As of September 30, 2013, we estimated that our actual achievement level for the performance-based RSUs granted during 2011, 2012 and 2013 will be approximately 130%, 120% and 100% of the predetermined performance conditions, respectively.

6. 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 62 drilling rigs which are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
East Texas	1
West Texas	18
North Dakota	11
Utah	7
Appalachia	4
Colombia	8
	62

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 109 well servicing rigs consisting of ninety-nine 550 horsepower rigs and ten 600 horsepower rigs. We currently provide wireline services and coiled tubing services with a fleet of 116 wireline units and 13 coiled tubing units, and we provide rental services with a gross book value of $17.2 million in 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 nine months ended September 30, 2013 and 2012 (amounts in thousands):

	As of and for the three months ended September 30, 2013			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$818,161	$401,609	$31,831	$1,251,601
Revenues	$131,033	$112,946	$—	$243,979
Operating costs	89,350	71,910	—	161,260
Segment margin	$41,683	$41,036	$—	$82,719
Depreciation and amortization	$30,993	$16,127	$294	$47,414
Capital expenditures	$17,417	$9,661	$357	$27,435

	As of and for the three months ended September 30, 2012			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$837,887	$441,791	$23,506	$1,303,184
Revenues	$125,662	$104,111	$—	$229,773
Operating costs	88,188	65,395	—	153,583
Segment margin	$37,474	$38,716	$—	$76,190
Depreciation and amortization	$27,467	$14,399	$201	$42,067
Capital expenditures	$56,734	$26,269	$402	$83,405

	As of and for the nine months ended September 30, 2013			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$818,161	$401,609	$31,831	$1,251,601
Revenues	$402,357	$319,646	$—	$722,003
Operating costs	267,630	202,662	—	470,292
Segment margin	$134,727	$116,984	$—	$251,711
Depreciation and amortization	$92,080	$48,139	$828	$141,047
Capital expenditures	$64,761	$35,895	$1,489	$102,145

	As of and for the nine months ended September 30, 2012			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$837,887	$441,791	$23,506	$1,303,184
Revenues	$369,014	$322,561	$—	$691,575
Operating costs	247,896	191,774	—	439,670
Segment margin	$121,118	$130,787	$—	$251,905
Depreciation and amortization	$79,263	$40,508	$658	$120,429
Capital expenditures	$217,926	$85,457	$1,375	$304,758

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 nine months ended September 30, 2013 and 2012 (amounts in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Segment margin	$82,719	$76,190	$251,711	$251,905
Depreciation and amortization	(47,414)	(42,067)	(141,047)	(120,429)
General and administrative	(23,896)	(21,269)	(70,872)	(64,677)
Bad debt recovery (expense)	(35)	368	(453)	515
Impairment charges	(9,504)	—	(54,292)	(1,032)
Income (loss) from operations	$1,870	$13,222	$(14,953)	$66,282

The following table sets forth certain financial information for our international operations in Colombia as of and for the three and nine months ended September 30, 2013 and 2012 (amounts in thousands):

	As of and for the three months ended September 30,		As of and for the nine months ended September 30,	
	2013	2012	2013	2012
Identifiable assets	$153,287	$153,309	$153,287	$153,309
Revenues	$29,959	$24,405	$91,361	$70,706

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.

7. 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 $35.0 million relating to our performance under these bonds as of September 30, 2013.

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.

8. Guarantor/Non-Guarantor Condensed Consolidated Financial Statements

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by all existing domestic subsidiaries, except for Pioneer Services Holdings, LLC, and certain of our future domestic subsidiaries. Effective October 1, 2012, the Indenture was supplemented to add Pioneer Coiled Tubing Services, LLC (formerly Go-Coil, L.L.C.) as a subsidiary guarantor. 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 September 30, 2013, 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.

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CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited, in thousands)

	September 30, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$17,588	$(3,145)	$2,642	$—	$17,085
Receivables, net of allowance	961	137,099	44,477	(448)	182,089
Intercompany receivable (payable)	(24,835)	49,364	(24,529)	—	—
Deferred income taxes	937	7,369	4,291	—	12,597
Inventory	—	6,872	5,860	—	12,732
Prepaid expenses and other current assets	1,138	2,875	1,696	—	5,709
Total current assets	(4,211)	200,434	34,437	(448)	230,212
Net property and equipment	4,134	867,958	88,150	(750)	959,492
Investment in subsidiaries	980,404	120,077	—	(1,100,481)	—
Intangible assets, net of accumulated amortization	72	34,254	—	—	34,326
Noncurrent deferred income taxes	71,779	—	1,335	(71,779)	1,335
Assets held for sale	—	6,718	—	—	6,718
Other long-term assets	8,025	2,134	9,359	—	19,518
Total assets	$1,060,203	$1,231,575	$133,281	$(1,173,458)	$1,251,601
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$907	$42,695	$4,488	(448)	$47,642
Current portion of long-term debt	—	23	—	—	23
Deferred revenues	—	906	—	—	906
Accrued expenses	5,050	45,219	7,513	—	57,782
Total current liabilities	5,957	88,843	12,001	(448)	106,353
Long-term debt, less current portion	534,333	88	—	—	534,421
Noncurrent deferred income taxes	—	157,057	—	(71,779)	85,278
Other long-term liabilities	291	5,183	1,203	—	6,677
Total liabilities	540,581	251,171	13,204	(72,227)	732,729
Total shareholders' equity	519,622	980,404	120,077	(1,101,231)	518,872
Total liabilities and shareholders' equity	$1,060,203	$1,231,575	$133,281	$(1,173,458)	$1,251,601

	December 31, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$18,479	$(5,401)	$10,655	$—	$23,733
Receivables, net of allowance	440	129,570	29,128	(294)	158,844
Intercompany receivable (payable)	(124,516)	146,652	(22,136)	—	—

Deferred income taxes	869	8,162	2,027	—	11,058
Inventory	—	5,956	6,155	—	12,111
Prepaid expenses and other current assets	655	9,163	3,222	—	13,040
Total current assets	(104,073)	294,102	29,051	(294)	218,786
Net property and equipment	3,474	921,393	90,223	(750)	1,014,340
Investment in subsidiaries	1,122,814	114,416	—	(1,237,230)	—
Intangible assets, net of accumulated amortization	68	43,775	—	—	43,843
Goodwill	—	41,683	—	—	41,683
Noncurrent deferred income taxes	51,834	—	5,519	(51,834)	5,519
Other long-term assets	9,582	2,340	3,683	—	15,605
Total assets	$1,083,699	$1,417,709	$128,476	$(1,290,108)	$1,339,776
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$1,558	$76,828	$5,437	$—	$83,823
Current portion of long-term debt	—	872	—	—	872
Deferred revenues	—	1,954	1,926	—	3,880
Accrued expenses	14,905	48,892	4,472	(294)	67,975
Total current liabilities	16,463	128,546	11,835	(294)	156,550
Long-term debt, less current portion	518,618	107	—	—	518,725
Noncurrent deferred income taxes	(4)	160,676	—	(51,834)	108,838
Other long-term liabilities	192	5,566	2,225	—	7,983
Total liabilities	535,269	294,895	14,060	(52,128)	792,096
Total shareholders' equity	548,430	1,122,814	114,416	(1,237,980)	547,680
Total liabilities and shareholders' equity	$1,083,699	$1,417,709	$128,476	$(1,290,108)	$1,339,776

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	Three months ended September 30, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$214,020	$29,959	$—	$243,979
Costs and expenses:					
Operating costs	—	138,961	22,299	—	161,260
Depreciation and amortization	294	43,794	3,326	—	47,414
General and administrative	7,052	16,110	872	(138)	23,896
Intercompany leasing	—	(1,215)	1,215	—	—
Bad debt expense (recovery)	—	35	—	—	35
Impairment charges	—	9,504	—	—	9,504
Total costs and expenses	7,346	207,189	27,712	(138)	242,109
Income (loss) from operations	(7,346)	6,831	2,247	138	1,870
Other income (expense):					
Equity in earnings of subsidiaries	6,377	1,845	—	(8,222)	—
Interest expense	(12,320)	(13)	9	—	(12,324)
Other	3	568	177	(138)	610
Total other income (expense)	(5,940)	2,400	186	(8,360)	(11,714)
Income (loss) before income taxes	(13,286)	9,231	2,433	(8,222)	(9,844)
Income tax expense (benefit)	7,056	(2,854)	(588)	—	3,614
Net income (loss)	$(6,230)	$6,377	$1,845	$(8,222)	$(6,230)

	Three months ended September 30, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$191,753	$38,020	$—	$229,773
Costs and expenses:					
Operating costs	—	125,295	28,288	—	153,583
Depreciation and amortization	201	35,727	6,139	—	42,067
General and administrative	5,653	12,780	2,974	(138)	21,269
Intercompany leasing	—	(1,215)	1,215	—	—
Bad debt expense (recovery)	—	(412)	44	—	(368)
Total costs and expenses	5,854	172,175	38,660	(138)	216,551
Income (loss) from operations	(5,854)	19,578	(640)	138	13,222
Other income (expense):					
Equity in earnings of subsidiaries	11,274	(441)	—	(10,833)	—
Interest expense	(9,440)	(26)	13	—	(9,453)
Other	477	210	(242)	(138)	307
Total other income (expense)	2,311	(257)	(229)	(10,971)	(9,146)
Income (loss) before income taxes	(3,543)	19,321	(869)	(10,833)	4,076
Income tax expense (benefit)	6,158	(8,047)	428	—	(1,461)
Net income (loss)	$2,615	$11,274	$(441)	$(10,833)	$2,615

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	Nine months ended September 30, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$630,642	$91,361	$—	$722,003
Costs and expenses:					
Operating costs	—	406,806	63,486	—	470,292
Depreciation and amortization	828	130,241	9,978	—	141,047
General and administrative	18,563	50,272	2,451	(414)	70,872
Intercompany leasing	—	(3,645)	3,645	—	—
Bad debt expense (recovery)	67	386	—	—	453
Impairment charges	—	54,292	—	—	54,292
Total costs and expenses	19,458	638,352	79,560	(414)	736,956
Income (loss) from operations	(19,458)	(7,710)	11,801	414	(14,953)
Other (expense) income:					
Equity in earnings of subsidiaries	2,111	5,698	—	(7,809)	—
Interest expense	(36,110)	(33)	26	—	(36,117)
Other	5	1,425	(2,476)	(414)	(1,460)
Total other (expense) income	(33,994)	7,090	(2,450)	(8,223)	(37,577)
Income (loss) before income taxes	(53,452)	(620)	9,351	(7,809)	(52,530)
Income tax (expense) benefit	20,035	2,731	(3,653)	—	19,113
Net income (loss)	$(33,417)	$2,111	$5,698	$(7,809)	$(33,417)

	Nine months ended September 30, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$575,927	$115,648	$—	$691,575
Costs and expenses:					
Operating costs	—	356,880	82,790	—	439,670
Depreciation and amortization	658	102,216	17,555	—	120,429
General and administrative	16,713	40,151	8,227	(414)	64,677
Intercompany leasing	—	(3,645)	3,645	—	—
Bad debt expense (recovery)	—	(687)	172	—	(515)
Impairment charges	—	1,032	—	—	1,032
Total costs and expenses	17,371	495,947	112,389	(414)	625,293
Income (loss) from operations	(17,371)	79,980	3,259	414	66,282
Other (expense) income:					
Equity in earnings of subsidiaries	52,794	3,820	—	(56,614)	—
Interest expense	(26,648)	(23)	13	—	(26,658)
Other	337	710	626	(414)	1,259
Total other (expense) income	26,483	4,507	639	(57,028)	(25,399)
Income (loss) before income taxes	9,112	84,487	3,898	(56,614)	40,883
Income tax (expense) benefit	17,360	(31,693)	(78)	—	(14,411)
Net income (loss)	$26,472	$52,794	$3,820	$(56,614)	$26,472

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

	Nine months ended September 30, 2013			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$(14,040)	$123,670	$445	$110,075
Cash flows from investing activities:				
Purchases of property and equipment	(2,043)	(126,738)	(9,164)	(137,945)
Proceeds from sale of property and equipment	—	6,192	706	6,898
	(2,043)	(120,546)	(8,458)	(131,047)
Cash flows from financing activities:				
Debt repayments	(25,000)	(868)	—	(25,868)
Proceeds from issuance of debt	40,000	—	—	40,000
Debt issuance costs	(13)	—	—	(13)
Proceeds from exercise of options	833	—	—	833
Purchase of treasury stock	(628)	—	—	(628)
	15,192	(868)	—	14,324
Net increase (decrease) in cash and cash equivalents	(891)	2,256	(8,013)	(6,648)
Beginning cash and cash equivalents	18,479	(5,401)	10,655	23,733
Ending cash and cash equivalents	$17,588	$(3,145)	$2,642	$17,085

	Nine months ended September 30, 2012			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$(162,064)	$270,791	$20,585	$129,312
Cash flows from investing activities:				
Purchases of property and equipment	(1,474)	(262,071)	(27,506)	(291,051)
Proceeds from sale of property and equipment	—	2,361	72	2,433
	(1,474)	(259,710)	(27,434)	(288,618)
Cash flows from financing activities:				
Debt repayments	—	(850)	(19)	(869)
Proceeds from issuance of debt	80,000	—	—	80,000
Debt issuance costs	(58)	—	—	(58)
Proceeds from exercise of options	684	—	—	684
Purchase of treasury stock	(357)	—	—	(357)
	80,269	(850)	(19)	79,400
Net increase (decrease) in cash and cash equivalents	(83,269)	10,231	(6,868)	(79,906)
Beginning cash and cash equivalents	91,932	(13,879)	8,144	86,197
Ending cash and cash equivalents	$8,663	$(3,648)	$1,276	$6,291

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 exploration and development projects to be made by oil and gas exploration and production companies, economic cycles and their impact on capital markets and liquidity, the continued demand for 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, changes in technology and improvements in our competitors' equipment, 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, 2012, 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, 2012 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 Energy Services (formerly called "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 acquired two production services companies which significantly expanded our service offerings to include 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.

In 2012, we changed our company name from "Pioneer Drilling Company" to "Pioneer Energy Services Corp." Our common stock trades on the New York Stock Exchange under the ticker symbol "PES." Our new name reflects 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 a diverse group of independent and large 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. We also provide coiled tubing and wireline services offshore in the Gulf of Mexico. 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: our Drilling Services Segment and our Production Services Segment. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 6, 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 62 drilling rigs which are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
East Texas	1
West Texas	18
North Dakota	11
Utah	7
Appalachia	4
Colombia	8
	62

In early 2011, we began construction of ten new-build AC drilling rigs that are fit for purpose for domestic shale plays, based on term contracts. We deployed seven of these new-build drilling rigs during 2012, and deployed the final three in early 2013. All of our new-build drilling rigs are currently operating in shale or unconventional plays under long-term drilling contracts.

During the second quarter of 2013, we sold two mechanical drilling rigs that were previously idle in our East Texas division, for which we recognized an associated gain of approximately $0.8 million. In September 2013, we decided to sell eight of our mechanical drilling rigs, for which we recognized an impairment charge of $9.2 million dollars during the third quarter. All eight drilling rigs are classified as held for sale at September 30, 2013 and were sold in late October 2013.

As of September 30, 2013, 56 of our 62 drilling rigs are earning revenues under drilling contracts, 42 of which are under term contracts. All except one of our drilling rigs in Colombia are currently under contract, six of which are working under term contracts that expire at the end of 2013 which we expect to renew. We are currently in negotiations to renew the contracts for our rigs in Colombia and we are actively marketing all of 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 existing or potential 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. A range of services are required in order to establish production in newly-drilled wells and to maintain production over the useful lives of active wells. We use our well servicing rig fleet to provide these necessary services, including the completion of newly-drilled wells, maintenance and workover of active wells, and plugging and abandonment of wells at the end of their useful lives. As of September 30, 2013, we operate ninety-nine 550 horsepower rigs and ten 600 horsepower rigs through 11 locations, most of which are in the Gulf Coast and ArkLaTex regions.

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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. To complete a well, the production casing must be perforated 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 September 30, 2013, we operate through 25 locations with a fleet of 116 wireline units.

- Coiled Tubing Services. Coiled tubing is an important element of the well servicing industry 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. As of September 30, 2013, our coiled tubing business consists of nine onshore and four offshore coiled tubing units which are currently deployed through four locations in Texas, Louisiana and Oklahoma.
- 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 three locations in Texas and Oklahoma. As of September 30, 2013 our fishing and rental tools have a gross book value of $17.2 million.

Pioneer Energy Services' corporate office is located at 1250 NE Loop 410, Suite 1000, San Antonio, Texas 78209. Our phone number is (855) 884-0575 and our website address is www.pioneeres.com. We make available free of charge though our website our Annual Reports on 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 oil and natural gas prices.

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 generally increasing oil prices in 2010 and 2011, exploration and production companies increased their exploration and production spending and industry equipment utilization and revenue rates improved, particularly in oil-producing regions and in certain shale regions. During 2012, modest increases in exploration and production spending resulted in modest increases in industry equipment utilization and revenue rates during 2012, as compared to 2011. Despite generally increasing oil prices during 2013, industry equipment utilization levels have been slightly lower than industry levels during 2012. In addition, excess natural gas production in the U.S. shale regions continues to depress natural gas prices. If oil and natural gas prices decline, then industry equipment utilization and revenue rates could decrease domestically and in Colombia.

Colombia has experienced significant growth in oil production since 2008 largely due to the infusion of capital by international exploration and production companies as a result of the country's improved regulation and security. Historically, Colombian oil prices have generally trended in line with West Texas Intermediate (WTI) oil prices. However, fluctuations in oil prices have a less significant impact on demand for drilling and production services in Colombia as compared to the impact on demand in North America. Demand for drilling and production services in Colombia is largely dependent upon the national oil company's long-term exploration and production programs.

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The trends in spot prices of WTI crude oil and Henry Hub natural gas, and the resulting trends in domestic land rig counts (per Baker Hughes) and domestic well servicing rig counts (per Guiberson/Association of Energy Service Companies) over the last five years are illustrated in the graphs below.

As shown in the charts above, the trends in industry rig counts are influenced by fluctuations in oil and natural gas prices, which affect the levels of capital and operating expenditures made by our clients.

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 as these expenditures are less sensitive to commodity price volatility. 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 and are generally evaluated according to a simple short-term payout criterion that 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.

Technological advancements and trends in our industry also affect the demand for certain types of equipment. During 2013, the demand for traditional drilling rigs in vertical markets has softened due to increased demand for drilling rigs that are able to drill horizontally. In addition, oil and gas exploration and production companies have increased the use of "pad drilling" in recent years whereby a series of horizontal wells are drilled in succession by a walking or skidding drilling rig at a single pad-site location. Pad drilling has improved the productivity of exploration and production activities which could reduce the demand for drilling rigs, particularly those that do not have the ability to walk or skid and to drill horizontal wells.

For additional information concerning the effects of the volatility in oil and gas prices and the effects of technological advancements and trends, see Item 1A – “Risk Factors” in Part I of our Annual Report on Form 10-K for the year ended December 31, 2012 and in Part II of this Form 10-Q.

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 which we operate in the most attractive drilling markets throughout the United States and in 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 where we currently operate and further enhance our geographic diversification through selective expansion. The key elements of this long-term strategy are focused on 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. All of the ten drilling rigs we recently constructed are currently operating in domestic shale and unconventional plays. Additionally, in recent years, we have added significant capacity to our production services fleets, which we believe are well positioned to capitalize on increased shale development.
- Exposure to Oil and Liquids Rich Natural Gas Drilling Activity. We believe that our flexible drilling and production services fleets allow us to pursue varied opportunities, enabling us to focus on a favorable mix of natural gas, oil and liquids rich natural gas activity. In recent years, we have intentionally increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions and we continue to actively seek contracts with oil-focused producers. As of September 30, 2013, approximately 96% of our working drilling rigs and 76% of our production services assets are operating on wells that are targeting or producing oil or liquids rich natural gas.
- International Presence. In 2007, we began operating 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. All except one of our drilling rigs in Colombia are currently under contract, six of which are under term contracts that expire at the end of 2013. We are currently in negotiations to renew the contracts for our rigs in Colombia.
- Growth Through Select Capital Deployment. We have historically invested in the growth of our business by strategically upgrading our existing assets, selectively engaging in new-build opportunities, and through selective acquisitions. We have continued to make significant investments in the growth of our business over the past several years. For example, on December 31, 2011, we acquired a coiled tubing services business to expand our existing production services offerings. We have also added significant capacity to our other production services fleets through the addition of 53 wireline units and 35 well servicing rigs since the beginning of 2010. In 2011, we began construction, based on term contracts, of ten new-build AC drilling rigs, all of which are currently operating in domestic shale or unconventional plays. With these capital projects recently completed, we have shifted our near-term focus toward reducing capital expenditures and using excess cash flows from operations to reduce outstanding debt balances and reposition ourselves for continued long-term growth.

Liquidity and Capital Resources

Sources of Capital Resources

Our principal liquidity requirements have been for working capital needs, debt service, capital expenditures and selective acquisitions. Our principal sources of liquidity consist of cash and cash equivalents (which equaled $17.1 million as of September 30, 2013), 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. As of September 30, 2013, the entire $300 million under the shelf registration statement is available for equity or debt offerings. In the future, we may consider equity and/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 September 30, 2013, we had $115.0 million outstanding under our Revolving Credit Facility and $8.9 million in committed letters of credit, which resulted in borrowing availability of $126.1 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 nine months ended September 30, 2013, we spent $137.9 million on purchases of property and equipment and placed into service property and equipment of $102.1 million. Currently, we expect to spend approximately $165 million on capital expenditures during 2013. We expect the total capital expenditures for 2013 will be allocated approximately 70% for our Drilling Services Segment and approximately 30% for our Production Services Segment. The total planned capital expenditures for the year ending December 31, 2013 includes the remaining construction costs of our new-build AC drilling rigs which were completed during 2013, upgrades to certain drilling rigs, additional production services equipment and routine capital expenditures. Actual capital expenditures may vary depending on the timing of commitments and payments, as well as the level of new-build and other expansion opportunities that meet our strategic and return on capital employed criteria. We expect to fund the remaining capital expenditures in 2013 from operating cash flow in excess of our working capital requirements.

Working Capital

Our working capital was $123.9 million at September 30, 2013, compared to $62.2 million at December 31, 2012. Our current ratio, which we calculate by dividing current assets by current liabilities, was 2.2 at September 30, 2013 compared to 1.4 at December 31, 2012.

Our operations have historically generated cash flows sufficient to meet our requirements for debt service and normal capital expenditures. However, our working capital requirements 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.

With the completion of our new-build drilling rig program in the first quarter of 2013, we have shifted our near-term focus toward reducing capital expenditures and using excess cash flows from operations to reduce outstanding debt balances.

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

	September 30, 2013	December 31, 2012	Change
Cash and cash equivalents	$17,085	$23,733	$(6,648)
Receivables:			
Trade, net of allowance for doubtful accounts	124,836	115,070	9,766
Unbilled receivables	45,048	35,140	9,908
Insurance recoveries	8,774	6,518	2,256
Income taxes and other	3,431	2,116	1,315
Deferred income taxes	12,597	11,058	1,539
Inventory	12,732	12,111	621
Prepaid expenses and other current assets	5,709	13,040	(7,331)
Current assets	230,212	218,786	11,426
Accounts payable	47,642	83,823	(36,181)
Current portion of long-term debt	23	872	(849)
Deferred revenues	906	3,880	(2,974)
Accrued expenses:			
Payroll and related employee costs	25,989	27,991	(2,002)
Insurance premiums and deductibles	10,707	9,708	999
Insurance claims and settlements	8,665	6,348	2,317
Interest	1,820	12,343	(10,523)
Other	10,601	11,585	(984)
Current liabilities	106,353	156,550	(50,197)
Working capital	$123,859	$62,236	$61,623

The decrease in cash and cash equivalents during the nine months ended September 30, 2013 is primarily due to $137.9 million used for purchases of property and equipment, which was mostly offset by $110.1 million of cash provided by operating activities, $14.1 million in proceeds from debt borrowings, net of repayments, and $6.9 million of proceeds from the sale of assets.

The net increase in our total trade and unbilled receivables as of September 30, 2013 as compared to December 31, 2012 is primarily due to the timing of the billing and collection cycles for long-term drilling contracts in Colombia, as well as the increase in revenues of $16.1 million, or 7%, for the quarter ended September 30, 2013 as compared to the quarter ended December 31, 2012.

The increase in both our insurance recoveries receivables and our insurance claims and settlements accrued expenses as of September 30, 2013 as compared to December 31, 2012 is primarily due to an increase in our insurance company's reserve for workers compensation claims in excess of our deductibles.

The increase in income taxes and other receivables primarily relates to an increase in sales tax receivables as of September 30, 2013 as compared to December 31, 2012.

The increase in current deferred income taxes as of September 30, 2013 as compared to December 31, 2012 is due to a movement of our deferred tax assets related to net operating losses from long-term to current, as we expect to realize them in the short term. The increase was mostly offset by a reduction in the current deferred tax assets for our annual bonus accruals which were paid in the first quarter of 2013.

The decrease in prepaid expenses and other assets as of September 30, 2013 as compared to December 31, 2012 is primarily due to the amortization of deferred mobilization costs relating to drilling contracts for our new-build drilling rigs and other drilling rigs that moved between geographic regions of the United States and Colombia, and a decrease in our prepaid insurance balance. Most of our insurance premiums are renewed in October of each year, and therefore our prepaid insurance balance was almost fully amortized as of September 30, 2013, whereas we had only three months of amortization at December 31, 2012.

The decrease in accounts payable is primarily due to a $35.8 million decrease in our accruals for capital expenditures as of September 30, 2013 as compared to December 31, 2012, as we completed construction of three of our new-build drilling rigs during the first quarter of 2013.
The decrease in deferred revenues is primarily related to the amortization of deferred mobilization revenues for drilling rigs in Colombia which moved between geographic regions in 2012.
The decrease in accrued payroll and employee related costs is primarily due to lower payroll accruals resulting from fewer payroll days reflected in the accrued payroll at September 30, 2013 as compared to December 31, 2012, due to the timing of pay periods.
The increase in our accrued insurance premiums and deductibles is primarily due to an increase in our accrual for workers compensation claims and health insurance costs resulting from an increase in our estimated liability for the deductibles under these policies.
The decrease in accrued interest expense is primarily due to the payment of interest on our Senior Notes which is due semi-annually on March 15 and September 15.
The decrease in other accrued expenses as of September 30, 2013 as compared to December 31, 2012 is primarily due to a decrease in our sales tax accrual which primarily related to the construction of our new-build drilling rigs which were completed in the first quarter of 2013.
Long-term Debt and Other Contractual Obligations
The following table includes information about the amount and timing of our contractual obligations at September 30, 2013 (amounts in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Within 1 Year	2 to 3 Years	4 to 5 Years	Beyond 5 Years
Long-term debt	$540,112	$23	$115,055	$425,034	$—
Interest on long-term debt	198,141	45,344	89,843	62,954	—
Purchase commitments	15,152	15,152	—	—	—
Operating leases	18,116	5,072	6,323	3,945	2,776
Other long-term liabilities	12,658	5,480	7,178	—	—
Total	$784,179	$71,071	$218,399	$491,933	$2,776

At September 30, 2013, long-term debt consists of $425 million face amount outstanding under our Senior Notes, $115.0 million outstanding under our Revolving Credit Facility and $0.1 million of other debt outstanding. The $115.0 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 million face amount outstanding under our Senior Notes will mature on March 15, 2018. Our Senior Notes have a carrying value of $419.3 million as of September 30, 2013, which represents the $425.0 million face value net of the $7.0 million of original issue discount and $1.3 million of original issue premium, net of amortization, based on the effective interest method.
Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 2.9% interest rate that was in effect at September 30, 2013, and (2) the outstanding balance of $115.0 million at September 30, 2013 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.
Purchase commitments primarily relate to equipment upgrades and purchases of other new equipment.
Operating leases consist of lease agreements for office space, operating facilities, equipment and personal property.
Other long-term liabilities include both current and noncurrent portions of the net equity tax payable to the Colombian tax authority and long-term incentive compensation which is payable to our employees, generally contingent upon their continued employment through the date of each respective award's payout.

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 September 30, 2013, we were in compliance with our financial covenants under the Revolving Credit Facility. Our total consolidated leverage ratio was 2.2 to 1.0, our senior consolidated leverage ratio was 0.5 to 1.0, and our interest coverage ratio was 5.5 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 September 30, 2013, 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 are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Effective October 1, 2012, Pioneer Coiled Tubing Services, LLC (formerly Go-Coil, L.L.C.) was added as a subsidiary guarantor under the Revolving Credit Facility. 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 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 by certain of our future domestic subsidiaries. Effective October 1, 2012, the Indenture was supplemented to add Pioneer Coiled Tubing Services, LLC (formerly Go-Coil, L.L.C.) as a subsidiary guarantor. 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 September 30, 2013, 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 nine months ended September 30, 2013 and 2012 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Drilling Services Segment:				
Revenues	$131,033	$125,662	$402,357	$369,014
Operating costs	89,350	88,188	267,630	247,896
Drilling Services Segment margin	$41,683	$37,474	$134,727	$121,118
Average number of drilling rigs	70.0	66.0	70.3	64.1
Utilization rate	80%	86%	84%	87%
Revenue days	5,174	5,214	16,050	15,310
Average revenues per day	$25,325	$24,101	$25,069	$24,103
Average operating costs per day	17,269	16,914	16,675	16,192
Drilling Services Segment margin per day	$8,056	$7,187	$8,394	$7,911
Production Services Segment:				
Revenues	$112,946	$104,111	$319,646	$322,561
Operating costs	71,910	65,395	202,662	191,774
Production Services Segment margin	$41,036	$38,716	$116,984	$130,787
Combined:				
Revenues	$243,979	$229,773	$722,003	$691,575
Operating costs	161,260	153,583	470,292	439,670
Combined margin	$82,719	$76,190	$251,711	$251,905

Adjusted EBITDA	$59,398	$55,596	$178,926	$189,002

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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. 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 (a) in isolation of, or as a substitute for, net income (loss), (b) as an indication of cash flows from operating activities or (c) as a measure of liquidity. In addition, Adjusted EBITDA does not represent funds available for discretionary use. We define Adjusted EBITDA as income (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 combined Drilling Services Segment margin and Production Services Segment margin to net income (loss), as reported, and a reconciliation of Adjusted EBITDA to net income (loss), as reported, are set forth in the following table.

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(amounts in thousands)			
Reconciliation of combined margin and Adjusted EBITDA to net income (loss):				
Combined margin	$82,719	$76,190	$251,711	$251,905
General and administrative	(23,896)	(21,269)	(70,872)	(64,677)
Bad debt (expense) recovery	(35)	368	(453)	515
Other (expense) income	610	307	(1,460)	1,259
Adjusted EBITDA	59,398	55,596	178,926	189,002
Depreciation and amortization	(47,414)	(42,067)	(141,047)	(120,429)
Impairment charges	(9,504)	—	(54,292)	(1,032)
Interest expense	(12,324)	(9,453)	(36,117)	(26,658)
Income tax benefit (expense)	3,614	(1,461)	19,113	(14,411)
Net income (loss)	$(6,230)	$2,615	$(33,417)	$26,472

Our Drilling Services Segment's revenues increased by $5.4 million, or 4%, and our operating costs increased by $1.2 million, or 1%, during the three months ended September 30, 2013, as compared to the corresponding period in 2012, primarily due to increased utilization in Colombia, where our revenues and costs per day are higher than our domestic drilling rigs. The overall increases in revenues and operating costs were partially offset by a slight decrease in utilization for our domestic drilling rigs, despite an increase in domestic revenues per day attributable to the operations of our new-build drilling rigs during 2013.

Our Drilling Services Segment's revenues increased by $33.3 million, or 9%, and our operating costs increased by $19.7 million, or 8%, during the nine months ended September 30, 2013, as compared to the corresponding period in 2012, primarily due to the 5% increase in revenue days. The increase in revenue days, as well as higher revenues per day, was primarily due to increased utilization in Colombia, as well as the expansion of our drilling rig fleet through the ten new-build drilling rigs, the majority of which were deployed in the second half of 2012 with the remaining three in the first quarter of 2013. Higher revenues and costs during 2013 are also partially due to the expansion of our fleet in areas of the U.S. which experience higher revenues and costs per day, due to higher demand.

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 to improve our Drilling Services Segment's margins. Turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts. We completed nine and fifteen turnkey contracts during the three and nine months ended September 30, 2013, respectively, as compared to two and eight turnkey drilling contracts completed during the corresponding periods in 2012, respectively. The following table provides the percentages of our drilling revenues by drilling contract type for the three and nine months ended September 30, 2013 and 2012:

	Three months ended September 30,				Nine months ended September 30,			
	2013		2012		2013		2012	
Daywork contracts	98	%	98	%	98	%	97	%
Turnkey contracts	2	%	2	%	2	%	3	%

Our Production Services Segment's revenues increased by $8.8 million, or 8%, and decreased by $2.9 million, or 1%, for the three and nine months ended September 30, 2013, respectively as compared to the corresponding periods in 2012. Our Production Services Segment's revenues increased during the three months ended September 30, 2013, as compared to the corresponding period in 2012, primarily due to the expansion of our wireline and well servicing operations through fleet additions made during 2012. In addition, we experienced strong demand for our well and wireline services during the three months ended September 30, 2013 which also resulted in slightly higher revenues for these services, as compared to the corresponding period in 2012. The decrease in our Production Services Segment's revenues during the nine months ended September 30, 2013 is primarily attributable to decreased demand for our coiled tubing and wireline services, which resulted in lower utilization and pricing for these services during the nine months ended September 30, 2013, as compared to the corresponding periods in 2012. The overall decrease in our production services revenues was partially offset by the expansion of our wireline and well servicing operations as well as increased pricing for our well servicing operations during the nine months ended September 30, 2013.

Our Production Services Segment's operating costs increased by $6.5 million, or 10%, and $10.9 million, or 6%, for the three and nine months ended September 30, 2013, respectively, as compared to the corresponding periods in 2012. The increases in our operating costs is primarily due to the expansion of our operations through fleet additions during 2012, though we also experienced some increase in our operating costs due to modest inflation of labor costs in our Production Services Segment during 2013.

Our general and administrative expense increased by approximately $2.6 million, or 12%, and $6.2 million, or 10%, for the three and nine months ended September 30, 2013, respectively, as compared to the corresponding periods in 2012. The increase is primarily due to increases in payroll and compensation related expenses resulting from the the expansion of our operations in both our Drilling Services and Production Services Segments.

Our other expense of $1.5 million and other income of $1.3 million for the nine months ended September 30, 2013 and 2012, respectively, is primarily related to foreign currency exchange gains and losses recognized for our Colombian operations.

Our depreciation and amortization expenses increased by $5.3 million and $20.6 million for the three and nine months ended September 30, 2013, respectively, as compared to the corresponding periods in 2012. This increase resulted primarily from the expansion of our operations through our new-build drilling rigs that went into service in 2012 and early 2013, as well as fleet additions in our Production Services Segment.

We recorded impairment charges on our property and equipment of $9.5 million for the nine months ended September 30, 2013 in association with our decision to place eight of our mechanical drilling rigs and other production services equipment as held for sale. During the nine months ended September 30, 2012, we recorded impairment charges on our property and equipment 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, as well as two wireline units and other wireline equipment.

During the nine months ended September 30, 2013, we recorded $44.8 million of impairment charges to reduce the goodwill and intangible asset carrying values of our coiled tubing reporting unit, which were originally recorded in connection with the acquisition of Go-Coil on December 31, 2011. On June 30, 2013, we performed an impairment analysis that led us to conclude that there would be no remaining implied value attributable to our goodwill and accordingly, we recorded a non-cash charge of $41.7 million for the full impairment of our goodwill. In addition, we performed an intangible asset impairment analysis on June 30, 2013, which resulted in a non-cash impairment charge of $3.1 million to reduce our intangible asset carrying value of client relationships. These impairment charges did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain

coiled tubing markets where we operate and a decline in our projected cash flows for the coiled tubing reporting unit.
Our interest expense increased for the three and nine months ended September 30, 2013, as compared to the corresponding periods in 2012, primarily due to the borrowings under our revolving credit facility during 2012 and early 2013, which increased our overall debt balance in 2013. The overall increase in interest expense was also due to less capitalized interest during the three

and nine months ended September 30, 2013, as compared to the corresponding periods in 2012, associated with the capital expenditures for our new-build drilling rigs and for upgrades to our drilling rig fleet.

Our effective income tax rate for the nine months ended September 30, 2013 was 36%, which is slightly higher than the federal statutory rate in the United States, due to the impact of state income taxes, and partially offset by the effect of foreign translation, the impact of lower effective tax rates in foreign jurisdictions 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. With the increase in demand from 2010 through 2011, and the resulting tightening of labor markets, we had a wage rate increase of approximately 10% across multiple drilling divisions in January 2012. During 2013, we have experienced modest wage rate increases in our Production Services Segment.

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 5% to 10% during 2012, and we estimate that we will experience a similar increase in 2013.

Off-Balance Sheet Arrangements

We do not 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. Drilling contracts for individual wells are usually completed in less than 60 days. 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.

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.

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.

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.

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 “deferred revenues” 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 September 30, 2013 we had $0.9 million and $0.9 million of current deferred mobilization revenues and costs, respectively, and $0.6 million and $0.7 million of long-term deferred mobilization revenues and costs, respectively. Our deferred mobilization costs and revenues primarily related to long-term contracts for our new-build drilling rigs and long-term contracts for drilling rigs which we moved between drilling divisions. Amortization of deferred mobilization revenues was $5.1 million and $4.0 million for the nine months ended September 30, 2013 and 2012, respectively.

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 production services completed but not yet invoiced. Our unbilled receivables totaled $45.0 million at September 30, 2013, of which $0.7 million related to turnkey drilling contract revenues, $39.4 million represented revenue recognized but not yet billed on daywork drilling contracts in progress at September 30, 2013 and $4.9 million related to unbilled receivables for our Production Services Segment.

Long-lived tangible and intangible assets—We evaluate for potential impairment of long-lived tangible 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 an impairment evaluation, we estimate the future undiscounted net cash flows from the use and eventual disposition of long-lived tangible and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for the individual reporting units (well servicing, wireline, coiled tubing and fishing and rental services). 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 asset group, then we would determine the fair value of the asset group. 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 are inherently uncertain and require management judgment.

Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our long-lived tangible and intangible assets as of June 30, 2013. We determined that the sum of the estimated future undiscounted net cash flows for our coiled tubing services reporting unit was less than the carrying amount at June 30, 2013. We then performed a valuation of the assets which resulted in a non-cash impairment charge of $3.1 million to reduce our intangible asset carrying value of client relationships. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain coiled tubing markets where we operate and a decline in our projected cash flows for the coiled tubing reporting unit.

The most significant inputs used in our impairment analysis include the projected utilization and pricing of our coiled tubing services, which are classified as Level 3 inputs as defined by ASC Topic 820, Fair Value Measurements and Disclosures. An increase of 1% in either the utilization or pricing assumptions would have resulted in a decrease to our impairment charge for our long-lived intangible assets of approximately $1 million. Similarly, a decrease of 1% in either of these assumptions would have led to an approximate $1 million increase to our impairment charge. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating fair values and performing the impairment test are inherently uncertain and require management judgment.

Our impairment analysis did not result in any impairment charges to our coiled tubing tangible long-lived assets, substantially all of which was related to the 13 coiled tubing units. As discussed further below, we also recorded a non-cash impairment charge to reduce the carrying value of goodwill to zero.

In September 2013, we evaluated the drilling rigs in our fleet and decided to place eight of our mechanical drilling rigs as held for sale and recognized an impairment charge to reduce the carrying value of these assets to their estimated fair value, which was based on their sales price. The decision to sell these drilling rigs was primarily due to a decrease in demand for non-top drive mechanical rigs that drill vertical oil and gas wells. Our remaining drilling rig fleet includes mechanical rigs that are currently working, but which may have reduced utilization if demand for vertical drilling continues to soften. We performed an impairment evaluation on the remaining drilling rigs in our fleet which are similar to those that we decided to sell. In order to estimate our future undiscounted cash flows from the use and eventual disposition of these assets, we incorporated probabilities of selling these rigs in the near term, versus working them through the end of their remaining useful lives. Our analysis led us to conclude that no impairment exists as of September 30, 2013 for the remaining similar drilling rigs. If the demand for vertical drilling continues to soften and these remaining mechanical rigs become idle for an extended amount of time, then the probability of a near term sale may increase, which would likely result in an impairment charge, based on the current market value of these drilling rigs. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions.

Goodwill—Goodwill results from business acquisitions and represents the excess of acquisition costs over the fair value of the net assets acquired. In connection with the acquisition of the production services business from Go-Coil, we recorded $41.7 million of goodwill at December 31, 2011, all of which was allocated to the coiled tubing services reporting unit within our Production Services Segment.

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. In addition, these circumstances could lead to our net book value exceeding our market capitalization which is another indicator of a potential impairment of 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.

When estimating fair values of a reporting unit for our goodwill impairment test, we use an income approach which provides an estimated fair value based on the reporting unit’s anticipated cash flows that are discounted using a weighted average cost of capital rate. 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 at a rate that is based on our weighted average cost of capital and estimated industry average rates for cost of capital. To ensure the reasonableness of the estimated fair value of our reporting units, we consider current industry market multiples and we perform a reconciliation of our total market capitalization to the total estimated fair value of all our reporting units.

Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our goodwill as of June 30, 2013. We determined that the fair value of our coiled tubing services reporting unit was less than its carrying value, including goodwill, and therefore, we performed the second step of the goodwill impairment test which led us to conclude that there would be no remaining implied fair value attributable to goodwill. Accordingly, we recorded a non-cash impairment charge of $41.7 million to reduce the carrying value of our goodwill to zero. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain coiled tubing markets where we operate

and a decline in our projected cash flows for the coiled tubing reporting unit.
The most significant inputs used in our impairment analysis include the projected utilization and pricing of our coiled tubing services and the weighted average cost of capital (discount rate) used in order to calculate the discounted cash flows for the reporting unit. These inputs are classified as Level 3 inputs as defined by ASC Topic 820, Fair Value Measurements and Disclosures. We assumed a 13% discount rate to estimate the fair value of the coiled tubing services reporting unit. A decrease in this assumption of 5% would have resulted in a decrease to our goodwill impairment charge of approximately $3.5 million. An increase of 1% in either the utilization or pricing assumptions would have resulted in a decrease to our goodwill impairment charge of approximately $2 million or $3 million, respectively. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions

used in estimating fair values of reporting units and performing the goodwill impairment test are inherently uncertain and require management judgment.

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 unit, 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—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 determination of depreciation and amortization expense, our estimates of fair value for impairment evaluations, our estimate of deferred taxes, our estimate of the liability relating to the self-insurance portion of our health and workers' compensation insurance, and our estimate of compensation related accruals.

We consider the recognition of revenues and costs on turnkey and footage contracts to be critical accounting estimates. For these types of contracts, we recognize revenues and accrue estimated costs based on our estimate of the number of days to complete each contract and our estimate of the total costs to complete the contract. 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.

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. 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. However, 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 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. However, during periods of reduced demand for drilling rigs, our overall profitability on turnkey and footage contracts has historically exceeded our profitability on daywork contracts.

During the nine months ended September 30, 2013, we did not experience a loss on any of the turnkey contracts completed. As of September 30, 2013, we had $0.7 million of unbilled receivables related to one turnkey contract that was in progress at September 30, 2013 which was completed prior to the issuance of these financial statements.

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 had an allowance for doubtful accounts of $1.5 million at September 30, 2013.

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 September 30, 2013, we had $97.4 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 September 30, 2013 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $3.5 million and our workers' compensation, general liability and auto liability insurance of approximately $6.8 million. We have stop-loss coverage of $150,000 per covered individual per year 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.

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 September 30, 2013, we had $115.0 million outstanding under our Revolving Credit Facility, which is our only variable rate debt. The impact of a hypothetical 1% increase or decrease in interest rates on this amount of debt would have resulted in a corresponding increase or decrease, respectively, in interest expense of approximately $0.9 million, and a corresponding increase or decrease, respectively, in net income of approximately $0.6 million during the nine months ended September 30, 2013. This potential increase or decrease is based on the simplified assumption that the level of variable rate debt remains constant with an immediate across-the-board interest rate increase or decrease as of January 1, 2013.

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 our consolidated financial statements.

The impact of currency rate changes on our Colombian Peso denominated transactions and balances resulted in foreign currency losses of $2.5 million for the nine months ended September 30, 2013.

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 September 30, 2013, 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 September 30, 2013 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

Except as discussed below, there has been no material change in our risk factors as previously disclosed in Item 1A – "Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2012 (the "2012 Form 10-K"). In addition to the other information set forth in this Form 10-Q, you should carefully consider the factors discussed in Item 1A – "Risk Factors" in our 2012 Form 10-K, which could materially affect our business, financial condition or future results.

Technological advancements and trends in our industry affect the demand for certain types of equipment.

Technological advancements and trends in our industry also affect the demand for certain types of equipment. During 2013, the demand for traditional drilling rigs in vertical markets has softened due to increased demand for drilling rigs that are able to drill horizontally. In addition, oil and gas exploration and production companies have increased the use of "pad drilling" in recent years whereby a series of horizontal wells are drilled in succession by a walking or skidding drilling rig at a single pad-site location. Pad drilling has improved the productivity of exploration and production activities which could reduce the demand for drilling rigs, particularly those that do not have the ability to walk or skid and to drill horizontal wells.

Although we take measures to ensure that we use advanced technologies for drilling and production services equipment, changes in technology or improvements in our competitors' equipment could make our equipment less competitive or require significant capital investments to keep our equipment competitive.

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 September 30, 2013. We did not repurchase any common shares during the quarter ended September 30, 2013.

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 documents are exhibits to this Form 10-Q:

Exhibit Number		Description
3.1*	-	Restated Articles of Incorporation of Pioneer Energy Services Corp. (Form 8-K dated 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. (Form 10-Q dated August 7, 2012 (File No. 1-8182, Exhibit 4.1)).
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)).
4.6*	-	Second Supplemental Indenture, dated October 1, 2012, among Pioneer Coiled Tubing Services, LLC, Pioneer Energy Services Corp., the other subsidiary guarantors and Wells Fargo Bank, National Association, as trustee (Form 10-Q dated November 1, 2012 (File No. 1-8182, Exhibit 4.6)).
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.
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101**	-	

The following financial statements from Pioneer Energy Services Corp.’s Form 10-Q for the quarter ended September 30, 2013, 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.

* Incorporated by reference to the filing indicated.

** Filed herewith.

\# Furnished herewith.

SIGNATURES

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: October 30, 2013

Index to Exhibits

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