PIONEER ENERGY SERVICES CORP
Form 10-Q
July 30, 2015

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

FORM 10-Q

(Mark one)

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

For the quarterly period ended June 30, 2015

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

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

As of July 15, 2015, there were 64,496,689 shares of common stock, par value $0.10 per share, of the registrant outstanding.

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

	June 30, 2015 (unaudited)	December 31, 2014 (audited)
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$62,468	$34,924
Receivables:		
Trade, net of allowance for doubtful accounts	67,663	136,161
Unbilled receivables	12,635	38,002
Insurance recoveries	15,782	10,900
Other receivables	7,158	5,138
Deferred income taxes	5,996	10,998
Inventory	9,528	14,117
Assets held for sale	4,056	9,909
Prepaid expenses and other current assets	7,679	8,925
Total current assets	192,965	269,074
Property and equipment, at cost	1,510,666	1,702,273
Less accumulated depreciation	729,575	845,732
Net property and equipment	781,091	856,541
Intangible assets, net of accumulated amortization of $44.1 million and $40.3 million at June 30, 2015 and December 31, 2014, respectively	20,253	24,223
Noncurrent deferred income taxes	—	2,753
Other long-term assets	10,588	18,998
Total assets	$1,004,897	$1,171,589
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable	$49,302	$64,305
Current portion of long-term debt	—	27
Deferred revenues	26,113	3,315
Accrued expenses:		
Payroll and related employee costs	17,113	40,058
Insurance premiums and deductibles	9,501	12,829
Insurance claims and settlements	15,782	10,900
Interest	5,467	5,432
Other	7,920	10,326
Total current liabilities	131,198	147,192
Long-term debt, less current portion	410,000	455,053
Noncurrent deferred income taxes	54,556	69,578
Other long-term liabilities	3,097	4,702
Total liabilities	598,851	676,525
Commitments and contingencies (Note 9)		
Shareholders’ equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—

Common stock $.10 par value; 100,000,000 shares authorized; 64,481,110 and 63,820,126 shares outstanding at June 30, 2015 and December 31, 2014, respectively	6,494	6,414
Additional paid-in capital	473,370	472,457
Treasury stock, at cost; 454,577 and 317,103 shares at June 30, 2015 and December 31, 2014, respectively	(3,741)	(3,030)
Accumulated earnings	(70,077)	19,223
Total shareholders’ equity	406,046	495,064
Total liabilities and shareholders’ equity	$1,004,897	$1,171,589

See accompanying notes to condensed consolidated financial statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(in thousands, except per share data)			
Revenues:				
Drilling services	$58,559	$127,553	$156,974	$245,510
Production services	76,452	132,259	171,851	253,336
Total revenues	135,011	259,812	328,825	498,846
Costs and expenses:				
Drilling services	32,815	84,022	95,111	161,941
Production services	53,106	82,576	121,874	160,147
Depreciation and amortization	38,489	45,791	80,271	91,317
General and administrative	18,363	25,276	40,223	49,759
Bad debt expense	394	561	713	437
Impairment charges	71,329	—	77,319	—
Gain on dispositions of property and equipment	(4,377)	(331)	(3,244)	(1,731)
Gain on litigation	—	—	—	(2,876)
Total costs and expenses	210,119	237,895	412,267	458,994
Income (loss) from operations	(75,108)	21,917	(83,442)	39,852
Other income (expense):				
Interest expense, net of interest capitalized	(5,245)	(10,728)	(10,700)	(23,116)
Loss on extinguishment of debt	—	(14,595)	—	(22,482)
Other	486	2,017	(2,194)	1,815
Total other expense	(4,759)	(23,306)	(12,894)	(43,783)
Loss before income taxes	(79,867)	(1,389)	(96,336)	(3,931)
Income tax benefit	2,586	1,070	7,036	1,033
Net loss	$(77,281)	$(319)	$(89,300)	$(2,898)
Loss per common share—Basic	$(1.20)	$(0.01)	$(1.39)	$(0.05)
Loss per common share—Diluted	$(1.20)	$(0.01)	$(1.39)	$(0.05)
Weighted average number of shares outstanding—Basic	64,342	62,877	64,168	62,710
Weighted average number of shares outstanding—Diluted	64,342	62,877	64,168	62,710

See accompanying notes to condensed consolidated financial statements.

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

	Six months ended June 30, 2015	2014
	(in thousands)	
Cash flows from operating activities:		
Net loss	$(89,300)	$(2,898)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	80,271	91,317
Allowance for doubtful accounts	713	396
Gain on dispositions of property and equipment	(3,244)	(1,731)
Stock-based compensation expense	1,240	3,827
Amortization of debt issuance costs, discount and premium	827	1,504
Loss on extinguishment of debt	—	22,482
Impairment charges	77,319	—
Deferred income taxes	(8,267)	(3,762)
Change in other long-term assets	1,018	4,448
Change in other long-term liabilities	(1,606)	(1,284)
Changes in current assets and liabilities:		
Receivables	91,881	(23,463)
Inventory	1,001	(234)
Prepaid expenses and other current assets	1,384	(77)
Accounts payable	(26,220)	7,667
Deferred revenues	22,798	2,607
Accrued expenses	(28,044)	(5,312)
Net cash provided by operating activities	121,771	95,487
Cash flows from investing activities:		
Purchases of property and equipment	(84,027)	(74,567)
Proceeds from sale of property and equipment	34,538	6,538
Proceeds from insurance recoveries	227	—
Net cash used in investing activities	(49,262)	(68,029)
Cash flows from financing activities:		
Debt repayments	(45,002)	(330,013)
Proceeds from issuance of debt	—	320,000
Debt issuance costs	(5)	(6,187)
Tender premium costs	—	(15,381)
Proceeds from exercise of options	753	1,581
Purchase of treasury stock	(711)	(1,132)
Net cash used in financing activities	(44,965)	(31,132)
Net increase (decrease) in cash and cash equivalents	27,544	(3,674)
Beginning cash and cash equivalents	34,924	27,385
Ending cash and cash equivalents	$62,468	$23,711
Supplementary disclosure:		
Interest paid	$11,385	$25,250

Income tax paid	$2,331	$2,131
Noncash investing and financing activity:		
Change in capital expenditure accruals	$11,133	$3,346

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 Corp. 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 two of our services (coiled tubing and wireline services) offshore in the Gulf of Mexico.
Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies through our four drilling divisions in the US, and internationally in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs.
Since October 2014, domestic and international oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. In drilling, all rig classes were severely impacted by the industry downturn. However, AC drilling rigs equipped with either a walking or skidding system are the best suited for horizontal pad drilling and are the most desirable rig design available. During the first half of 2015, we sold 27 of our mechanical and lower horsepower electric drilling rigs. As of June 30, 2015, we continue to have three of this type of rig remaining in our fleet that are well suited for certain higher margin turnkey or horizontal drilling projects, and one rig classified as held for sale.
As the downturn worsened through the first half of 2015 resulting in significantly reduced revenue and utilization rates, and as current projections reflect a more delayed recovery than previously anticipated, we performed impairment testing on all the non-AC electric drilling rigs in our fleet, including the eight drilling rigs in Colombia which are currently idle. As a result, we recognized $71.3 million of impairment charges during the second quarter of 2015, primarily to reduce the carrying values of all eight drilling rigs in Colombia and certain other assets associated with our Colombian operations, as well as the six non-AC electric drilling rigs in our domestic fleet that are not pad-capable, to their estimated fair values.
As of June 30, 2015, the drilling rigs in our fleet, excluding the one rig classified as held for sale, are assigned to the following divisions:

Drilling Division	Rig Count
South Texas	11
West Texas	4
North Dakota	8
Appalachia	4
Colombia	8
	35

As of June 30, 2015, 18 of our 35 drilling rigs are earning revenues under drilling contracts, 15 of which are earning under term contracts. Our eight drilling rigs in Colombia are currently idle. We are actively marketing them to various operators in Colombia to diversify our client base, and evaluating other options including the possibility of the sale of some or all of our assets in Colombia.
In April 2015, we deployed our first of five new-build 1,500 horsepower AC drilling rigs to be delivered this year. We expect to deploy three new-build rigs in the third quarter and the final rig by the end of the year. Three of the remaining new-build drilling rigs to be deployed are under multi-year term contracts. The multi-year contract that was initially assigned to the fifth new-build drilling rig has been transferred to an existing AC rig in North Dakota that has a contract expiring in November 2015, thereby allowing us to market the fifth new-build rig to a new domestic client.

Including the five new-build drilling rigs, we expect to end 2015 with a drilling fleet of 39 rigs, of which 95% will be capable of drilling horizontally, with all but one of our AC rigs built within the last five years. The removal of older, less capable rigs from our fleet and the recent and ongoing investments in the construction of new-builds is transforming our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market.

Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing 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 June 30, 2015, we have a fleet of 121 well servicing rigs, consisting of 110 rigs with 550 horsepower and 11 rigs with 600 horsepower, 125 wireline units and 17 coiled tubing units. Our well servicing and coiled tubing utilization rates for the quarter ended June 30, 2015 were 73% and 24%, respectively, based on total fleet count.

Drilling Contracts

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 or turnkey 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 market contracts generally provide for the drilling of a single well and typically permit the client to terminate on short notice. We enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand. Currently, we have contracts with original terms of six months to four years in duration.

As of June 30, 2015, 18 of our 35 drilling rigs are earning revenues under drilling contracts, 15 of which are earning under term contracts, and which if not renewed prior to the end of their terms, will expire as follows:

		Term Contract Expiration by Period				
	Total	Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years	2 to 4 Years
Term Contracts	15	3	6	4	—	2

With most long-term drilling contracts, we are entitled to receive a full or reduced rate of revenue from our clients if they choose to place a rig on standby or to early terminate the contract before its original expiration term. Generally, these revenues are billed and collected over the remaining term of the contract, as the rig is placed on standby rather than fully released from the contract, and thus may go back to work at the client's decision any time before the end of the contract. Some of our drilling contracts contain "make-whole" provisions whereby if we are able to secure additional work for the rig with another client, then each party is entitled to a make-whole payment. If the dayrates under the new contract are less than the dayrates in the original contract, we would be entitled to a reduced revenue dayrate from the terminating client, and likewise, the terminating client may be entitled to a payment from us if the new contract dayrates exceed those of the original contract. A client may also choose to early terminate the contract and make an upfront early termination payment based on a per day rate for the remaining term of the contract. Revenues derived from rigs placed on standby or from the early termination of long-term drilling contracts are deferred and recognized as the amounts become fixed or determinable, over the remainder of the original term or when the rig is sold.

In response to the significant decline in oil prices during recent months, term contracts for 16 of our drilling rigs have been early terminated, including seven of our 15 drilling rigs that are currently earning revenues under term contracts, resulting in approximately $53.0 million of early termination revenues. Revenues derived from these early terminations are deferred and recognized over the remainder of the original term of the drilling contracts. We recognized $11.3 million and $16.0 million of revenue for early termination payments during the first and second quarters of 2015, respectively, and $0.3 million in the fourth quarter of 2014.

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

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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 unaudited 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, 2014.

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 expenses, our estimates of projected cash flows and fair values 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 June 30, 2015, through the filing of this Form 10-Q, for inclusion as necessary.

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 drilling contracts are invoiced upon completion of the contract.

Our unbilled receivables totaled $12.6 million at June 30, 2015, of which $11.8 million represented revenue recognized but not yet billed on daywork drilling contracts in progress at June 30, 2015 and $0.8 million related to unbilled receivables for our Production Services Segment. At December 31, 2014, our unbilled receivables totaled $38.0 million, of which $32.8 million represented revenue recognized but not yet billed on daywork drilling contracts in progress at December 31, 2014, $0.8 million related to turnkey drilling contract revenues, and $4.4 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.

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. 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 and coiled tubing). 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

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value of these assets. The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment.

Other Long-Term Assets

Other long-term assets consist of debt issuance costs net of amortization, cash deposits related to the deductibles on our workers' compensation insurance policies and the long-term portion of deferred mobilization costs.

Other Current Liabilities

Our other accrued expenses include accruals for items such as property tax, sales tax, Colombian net wealth tax, professional and other fees. We routinely expense these items in the normal course of business over the periods these expenses benefit.

Other Long-Term Liabilities

Our other long-term liabilities consist of the noncurrent portion of liabilities associated with our long-term compensation plans and other deferred liabilities.

Related-Party Transactions

During the six months ended June 30, 2015 and 2014, the Company paid approximately $0.1 million and $0.2 million, respectively, for trucking and equipment rental services, which represented arms-length transactions, to Gulf Coast Lease Service, a trucking and construction company. Joe Freeman, our Senior Vice President of Well Servicing, serves as the President of Gulf Coast Lease Services, which is owned and operated by Mr. Freeman's two sons. Mr. Freeman does not receive compensation from Gulf Coast Lease Service, and he serves primarily in an advisory role to his sons.

Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, a comprehensive new revenue recognition standard that will supersede nearly all existing revenue recognition guidance. The standard outlines a single comprehensive model for revenue recognition based on the core principle that a company will recognize revenue when promised goods or services are transferred to clients, in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. We are required to apply this new standard beginning with our first quarterly filing in 2017. In July 2015, the FASB decided to defer the effective date by one year (until 2018), but the FASB still needs to issue an ASU to change the effective date. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this new standard will have a material effect on our financial position or results of operations.

Debt Issuance Costs. On April 7, 2015, the FASB issued Accounting Standards Update ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and will be effective for us beginning with our first quarterly filing in 2016. Early adoption is permitted. We do not expect this adoption to have a material impact on our financial position or results of operations.

Reclassifications

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

2. Property and Equipment

During the six months ended June 30, 2015 and 2014, we had capital expenditures of $95.2 million and $77.9 million, respectively, which includes $1.5 million and $0.1 million, respectively, of capitalized interest costs incurred during the construction periods of new-build drilling rigs and other drilling equipment. Capital expenditures during 2015 primarily relate to our five new-build drilling rigs which began construction during 2014, as well as unit additions to our production services fleets. As of June 30, 2015 and December 31, 2014, capital expenditures incurred for property and equipment not yet placed in service was $98.2 million and $82.7 million, respectively.

During the six months ended June 30, 2015, we recorded total gains on disposition of our property and equipment of $3.2 million, primarily for the sales of 27 of our mechanical and lower horsepower electric drilling rigs and other drilling equipment which we sold for aggregate net proceeds of $33.4 million, of which $0.8 million was recognized as a receivable at June 30, 2015. During the six months ended June 30, 2014, we recorded total gains on disposition of our property and equipment of $1.7 million, of which $1.1 million was related to the sale of our trucking assets in February 2014.

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. 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 and coiled tubing). For our Drilling Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for individual domestic drilling rig assets and for our Colombian drilling rig assets as a group. 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.

Since October 2014, domestic and international oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. In drilling, all rig classes were severely impacted by the industry downturn. However, AC drilling rigs equipped with either a walking or skidding system are the best suited for horizontal pad drilling and are the most desirable rig design available. As the downturn worsened through the first half of 2015 resulting in significantly reduced revenue and utilization rates, and as current projections reflect a more delayed recovery than previously anticipated, we performed impairment testing on all the non-AC electric drilling rigs in our fleet, including the eight drilling rigs in Colombia which are currently idle. We also performed an impairment test on our coiled tubing operations, which have a net book value of $90.0 million at June 30, 2015.

In order to estimate our future undiscounted cash flows from the use and eventual disposition of our drilling assets, we incorporated probabilities of selling these assets in the near term, versus working them at a significantly reduced expected rate of utilization through the end of their remaining useful lives. The most significant assumptions used in our analysis are the expected margin per day and utilization, as well as the estimated proceeds upon any future sale or disposal of the assets. 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.

Our analysis indicated that the carrying value of our coiled tubing reporting unit was recoverable and thus there was no impairment present at June 30, 2015. Our analysis indicated that there was no impairment present for the six pad-capable non-AC drilling rigs in our fleet (those that are equipped with either a walking or skidding system), which have a total net book value of $47.4 million at June 30, 2015. However, our analysis indicated that the carrying values of the six non-AC drilling rigs in our domestic fleet which are not pad-capable, and our Colombian assets as a group, exceeded our estimated undiscounted cash flows for these assets. Therefore, an impairment charge was necessary to reduce the carrying values of these assets to their estimated fair values, which were based on market appraisals which are considered Level 3 inputs as defined by ASC Topic 820, Fair Value Measurements and Disclosures.

As a result, we recognized impairment charges of $50.2 million during the second quarter of 2015 to reduce the carrying values of all eight drilling rigs in Colombia and related drilling equipment, $3.6 million to reduce the carrying value of inventory in Colombia, $6.4 million to reduce the carrying value of nonrecoverable prepaid taxes associated with our Colombian operations, and $9.7 million to reduce the carrying values of the six non-AC electric drilling rigs in our domestic fleet that are not pad-capable, to their estimated fair values.

Additionally, during the three and six months ended June 30, 2015, we recognized impairment charges of $1.5 million and $7.5 million, respectively, to reduce the carrying values of assets which were classified as held for sale, to their estimated fair values, based on expected sales prices. As of June 30, 2015, our condensed consolidated balance sheet reflects assets held for sale of $4.1 million, which represents the fair value of one drilling rig, two wireline units, one real estate property and other drilling equipment.

These impairment charges are not expected to have an impact on our liquidity or debt covenants; however, they are a reflection of the overall downturn in our industry and decline in our projected future cash flows. If the demand for our drilling services remains at current levels or declines further and any of our rigs become or remain idle for an extended amount of time, then our estimated cash flows may further decrease, and the probability of a near term sale may increase. If any of the foregoing were to occur, we may incur additional impairment charges.

3. Valuation Allowances on Deferred Tax Assets

As of June 30, 2015, we had $80.7 million of deferred tax assets related to domestic and foreign net operating losses that are 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 domestic 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. The domestic net operating losses have a 20 year carryforward period and can be used to offset future domestic taxable income until their expiration, beginning in 2029, with the latest expiration in 2033. The foreign net operating losses have an indefinite carryforward period. However, as a result of the conditions leading to the impairment of our drilling rigs and other assets related to our Colombian operations, we recorded a valuation allowance of $21.1 million as of June 30, 2015 that fully offsets our foreign deferred tax assets relating to net operating losses and other tax benefits.

4. Debt

Our debt consists of the following (amounts in thousands):

	June 30, 2015	December 31, 2014
Senior secured revolving credit facility	$110,000	$155,000
Senior notes	300,000	300,000
Other	—	80
	410,000	455,080
Less current portion	—	(27)
	$410,000	$455,053

Senior Secured Revolving Credit Facility

We have a credit agreement, as amended on September 22, 2014, 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 $350 million, all of which matures on September 22, 2019 (the “Revolving Credit Facility”). In addition, at our request, and with the lenders' consent, the aggregate commitments of the lenders under the Revolving Credit Facility may be increased up to an additional $100 million provided that no default exists, all representations and warranties are true and correct, and compliance with financial covenants as set forth in the Revolving Credit Facility is met immediately prior to and after giving effect thereto. 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 $350 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 2.0% to 3.0% and 1.0% to 2.0%, respectively. The LIBOR margin and bank prime rate margin currently in effect are 2.25% and 1.25%, 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. Borrowings under the Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.
As of July 30, 2015, we had $110.0 million outstanding under our Revolving Credit Facility and $21.3 million in committed letters of credit, which resulted in borrowing availability of $218.7 million under our Revolving Credit Facility. There are no limitations on our ability to access this borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. At June 30, 2015, we were in compliance with our financial covenants under the Revolving Credit Facility. Our total consolidated leverage ratio was 2.1 to 1.0, our senior consolidated leverage ratio was 0.6 to 1.0, and our interest coverage ratio was 7.9 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 or repurchases of capital stock as long as (a) no event of default exists under the Revolving Credit Facility or would result from such capital expenditures or repurchases of capital stock, (b) after giving effect to such capital expenditures or repurchases of capital stock 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. In addition, the repurchase of capital stock requires, on a pro-forma basis, compliance with the maximum total leverage ratio and minimum interest coverage ratio as set forth in the Revolving Credit Facility, both before and after giving effect to such repurchase. If the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is equal to or greater than 2.00 to 1.00, then capital expenditures are limited to $100 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $30 million.
At June 30, 2015, 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, 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

In March 2010 and November 2011, we issued an aggregate $425 million of unregistered senior notes with a coupon interest rate of 9.875% that were set to mature in 2018 (the “2010 and 2011 Senior Notes”). The net proceeds from the 2010 issuance were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility and a portion of the net proceeds from the 2011 issuance were used to fund the acquisition of the coiled tubing business in December 2011. In order to reduce our overall interest expense and lengthen the overall maturity of our senior indebtedness, during 2014, we redeemed all of our outstanding 2010 and 2011 Senior Notes, funded primarily by proceeds from the issuance of our 2014 Senior Notes and additional borrowings under our Revolving Credit Facility, as well as some cash on hand.

In March 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the “2014 Senior Notes”). The 2014 Senior Notes were sold at 100% of their face value. After deductions were made for the $6.1 million for underwriters’ fees and other debt offering costs, we received $293.9 million of net proceeds which were used to fund the repayment of $300 million of aggregate principal amount of 2010 and 2011 Senior Notes in March and May 2014. During the three months ended March 31, 2014, we recognized a loss on debt extinguishment of $7.9 million for the redemption of $99.5 million of 2010 and 2011 Senior Notes in March 2014, which included redemption premiums of $5.5 million, $1.2 million of net unamortized discount and $1.2 million of unamortized debt issuance costs. Additionally, we recognized a loss on debt extinguishment during the three months ended June 30, 2014 of $14.6 million for the redemption of $200.5 million of 2010 and 2011 Senior Notes in May 2014, which included redemption premiums of $9.9 million, $2.4 million of net unamortized discount and $2.3 million of unamortized debt issuance costs.

The 2014 Senior Notes will mature on March 15, 2022 with interest due semi-annually in arrears on March 15 and September 15 of each year. We have the option to redeem the 2014 Senior Notes, in whole or in part, at any time on or after March 15, 2017 in each case at the redemption price specified in the Indenture dated March 18, 2014 (the Indenture) plus any accrued and unpaid interest and any additional interest (as defined in the Indenture) thereon to the date of redemption. Prior to March 15, 2017, we may also redeem the 2014 Senior Notes, in whole or in part, at a “make-whole” redemption price specified in the 2014 Indenture, plus any accrued and unpaid interest and any additional interest thereon to the date of redemption. In addition, prior to March 15, 2017, we may, on one or more occasions, redeem up to 35% of the aggregate principal amount of the 2014 Senior Notes at a redemption price equal to 106.125% of the principal amount thereof, plus accrued and unpaid interest and additional interest, if any, to the redemption date, with the net cash proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the 2014 Senior Notes remains outstanding after the occurrence of such redemption and that the redemption occurs within 120 days of the date of the closing of such equity offering.

In accordance with a registration rights agreement with the holders of our 2014 Senior Notes, we filed an exchange offer registration statement on Form S-4 with the Securities and Exchange Commission that became effective on October 2, 2014. The exchange offer registration statement enabled the holders of our Senior Notes to exchange their senior notes for publicly registered notes with substantially identical terms. References to the “Senior Notes” herein include the senior notes issued in the exchange offer.

If we experience a change of control (as defined in the Indenture), we will be required to make an offer to each holder of the Senior Notes to repurchase all or any part of the Senior Notes at a purchase price equal to 101% of the principal amount of each Senior Note, plus accrued and unpaid interest, if any, to the date of repurchase. If we engage in certain asset sales, within 365 days of such sale we will be required to use the net cash proceeds from such sale, to the extent we do not reinvest those proceeds in our business, to make an offer to repurchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, plus accrued and unpaid interest to the repurchase date.

The Indenture, among other things, limits us and certain of our subsidiaries in our ability to:

- pay dividends on stock, repurchase stock, redeem subordinated indebtedness or make other restricted payments and investments;
- incur, assume or guarantee additional indebtedness or issue preferred or disqualified stock;
- create liens on our or their assets;
- enter into sale and leaseback transactions;
- sell or transfer assets;
- 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 any other person;
- enter into transactions with affiliates; and
- enter into new lines of business.

The Senior Notes are not subject to any sinking fund requirements. The Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by certain of our existing domestic subsidiaries and by certain of our future domestic subsidiaries. (See Note 10, Guarantor/Non-Guarantor Condensed Consolidated Financial Statements.)

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 September 2019. Costs incurred in connection with the issuance of our 2014 Senior Notes were capitalized and are being amortized using the straight-line method (which approximates amortization using the interest method) over the term of the Senior Notes which mature in March 2022.

Capitalized debt costs related to the issuance of our long-term debt were $9.0 million and $9.8 million as of June 30, 2015 and December 31, 2014, respectively. We recognized $0.8 million and $1.1 million of associated amortization during the six months ended June 30, 2015 and 2014, respectively.

5. Fair Value of Financial Instruments

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

At June 30, 2015 and December 31, 2014, 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 June 30, 2015 and December 31, 2014 (amounts in thousands):

	June 30, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	$410,000	$353,032	$455,080	$415,785

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6. 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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Basic				
Net loss	$(77,281)	$(319)	$(89,300)	$(2,898)
Weighted-average shares	64,342	62,877	64,168	62,710
Loss per common share—Basic	$(1.20)	$(0.01)	$(1.39)	$(0.05)
Diluted				
Net loss	$(77,281)	$(319)	$(89,300)	$(2,898)
Weighted-average shares Outstanding	64,342	62,877	64,168	62,710
Diluted effect of outstanding stock options, restricted stock and restricted stock unit awards	—	—	—	—
	64,342	62,877	64,168	62,710
Loss per common share—Diluted	$(1.20)	$(0.01)	$(1.39)	$(0.05)

Potentially dilutive stock options, restricted stock and restricted stock unit awards representing a total of 4,717,647 and 4,893,961 shares of common stock for the three and six months ended June 30, 2015, respectively, and 3,213,088 and 4,170,854 for the three and six months ended June 30, 2014, respectively, were excluded from the computation of diluted weighted average shares outstanding due to their antidilutive effect.

7. Equity Transactions and Stock-Based Compensation Plans

Equity Transactions

In May 2015, 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 June 30, 2015, 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.

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 six months ended June 30, 2015 and 2014 (amounts in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Stock option awards	$213	$310	$477	$653
Restricted stock awards	99	141	223	294
Restricted stock unit awards	523	1,520	540	2,880
	$835	$1,971	$1,240	$3,827

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 June 30, 2015 or 2014. The following table summarizes the assumptions used in the Black-Scholes option pricing model based on a weighted-average calculation for the six months ended June 30, 2015 and 2014:

	Six months ended June 30,	
	2015	2014
Expected volatility	64 %	66 %
Risk-free interest rates	1.4 %	1.7 %
Expected life in years	5.52	5.49
Options granted	341,638	221,440
Grant-date fair value	$2.31	$4.87

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 six months ended June 30, 2015, 39,600 and 196,100 stock options, respectively, were exercised at a weighted-average exercise price of $3.84. During the three and six months ended June 30, 2014, 168,500 and 215,400 stock options were exercised at a weighted-average exercise price of $7.74 and $7.34, 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. During the six months ended June 30, 2015 and 2014, we granted 47,296 and 32,100 shares of restricted stock awards, with a weighted-average grant-date fair value of $7.40 and $14.33, 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 units granted during the three months ended June 30, 2014. The following table summarizes the number and weighted-average grant-date fair value of the restricted stock unit awards granted during the three months ended June 30, 2015 and the six months ended June 30, 2015 and 2014:

	Three months ended June 30,	Six months ended June 30,	
	2015	2015	2014
Time-based RSUs:			
Time-based RSUs granted	—	151,919	347,335
Weighted-average grant-date fair value	$—	$4.08	$8.44
Performance-based RSUs:			
Performance-based RSUs granted	145,107	439,773	321,606
Weighted-average grant-date fair value	$8.34	$5.76	$9.90

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 granted during 2012 and 2013, and half of the performance-based RSUs granted during 2014 and 2015, are subject to a market condition based on relative total shareholder return, as compared to that of our predetermined peer group, 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. The remaining performance-based RSUs are subject to performance conditions, based on our EBITDA and return on capital employed, relative to our predetermined peer group, 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.

In April 2015, we determined that 64% of the target number of shares granted during 2012 were actually earned based on the Company's achievement of certain performance measures, as compared to the predefined peer group, over the performance period from January 1, 2012 through December 31, 2014. The performance-based RSUs granted during 2012 vested and were converted to common stock at the end of April 2015. As of June 30, 2015, we estimated that our actual achievement level for the performance-based RSUs granted during 2013, 2014 and 2015 will be approximately 60%, 100% and 100% of the predetermined performance conditions, respectively.

8. 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.

Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies through our four drilling divisions in the US, and internationally in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs.

Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing 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.

The following tables set forth certain financial information for our two operating segments and corporate as of and for the three and six months ended June 30, 2015 and 2014 (amounts in thousands):

	As of and for the three months ended June 30, 2015			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$574,050	$356,669	$74,178	$1,004,897
Revenues	$58,559	$76,452	$—	$135,011
Operating costs	32,815	53,106	—	85,921
Segment margin	$25,744	$23,346	$—	$49,090
Depreciation and amortization	$20,815	$17,328	$346	$38,489
Capital expenditures	$42,634	$3,696	$14	$46,344

	As of and for the three months ended June 30, 2014			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$778,148	$413,308	$59,975	$1,251,431
Revenues	$127,553	$132,259	$—	$259,812
Operating costs	84,022	82,576	—	166,598
Segment margin	$43,531	$49,683	$—	$93,214
Depreciation and amortization	$28,969	$16,466	$356	$45,791
Capital expenditures	$19,383	$21,486	$127	$40,996

	As of and for the six months ended June 30, 2015			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$574,050	$356,669	$74,178	$1,004,897
Revenues	$156,974	$171,851	$—	$328,825
Operating costs	95,111	121,874	—	216,985
Segment margin	$61,863	$49,977	$—	$111,840
Depreciation and amortization	$44,415	$35,161	$695	$80,271
Capital expenditures	$75,690	$19,153	$317	$95,160

	As of and for the six months ended June 30, 2014			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$778,148	$413,308	$59,975	$1,251,431
Revenues	$245,510	$253,336	$—	$498,846
Operating costs	161,941	160,147	—	322,088
Segment margin	$83,569	$93,189	$—	$176,758
Depreciation and amortization	$58,208	$32,485	$624	$91,317
Capital expenditures	$40,639	$36,829	$445	$77,913

The following table reconciles the segment profits reported above to income from operations as reported on the consolidated statements of operations for the three and six months ended June 30, 2015 and 2014 (amounts in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Segment margin	$49,090	$93,214	$111,840	$176,758
Depreciation and amortization	(38,489)	(45,791)	(80,271)	(91,317)
General and administrative	(18,363)	(25,276)	(40,223)	(49,759)
Bad debt expense	(394)	(561)	(713)	(437)
Impairment charges	(71,329)	—	(77,319)	—
Gain on dispositions of property and equipment	4,377	331	3,244	1,731
Gain on litigation	—	—	—	2,876
Income (loss) from operations	$(75,108)	$21,917	$(83,442)	$39,852

The following table sets forth certain financial information for our international operations in Colombia as of and for the three and six months ended June 30, 2015 and 2014 (amounts in thousands):

	As of and for the three months ended June 30,		As of and for the six months ended June 30,	
	2015	2014	2015	2014
Identifiable assets	$65,902	$157,025	$65,902	$157,025
Revenues	$14,078	$25,527	$34,039	$47,691

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.

9. 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 $45.4 million relating to our performance under these bonds as of June 30, 2015.

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.

10. 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. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture.

In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes. As of June 30, 2015, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company.

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

CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited, in thousands)

	June 30, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	57,686	(2,033)	6,815	—	$62,468
Receivables, net of allowance	2,335	74,384	26,519	—	103,238
Intercompany receivable (payable)	(24,836)	41,788	(16,952)	—	—
Deferred income taxes	700	5,093	203	—	5,996
Inventory	—	6,378	3,150	—	9,528
Assets held for sale	—	4,056	—	—	4,056
Prepaid expenses and other current assets	1,192	4,972	1,515	—	7,679
Total current assets	37,077	134,638	21,250	—	192,965
Net property and equipment	3,652	741,734	35,705	—	781,091
Investment in subsidiaries	654,656	49,587	—	(704,243)	—
Intangible assets, net of accumulated amortization	—	20,253	—	—	20,253
Noncurrent deferred income taxes	119,992	—	—	(119,992)	—
Other long-term assets	9,466	1,122	—	—	10,588
Total assets	$824,843	$947,334	$56,955	$(824,235)	$1,004,897
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$986	$45,883	$2,433	—	$49,302
Current portion of long-term debt	—	—	—	—	—
Deferred revenues	—	26,113	—	—	26,113
Accrued expenses	7,393	43,682	4,708	—	55,783
Total current liabilities	8,379	115,678	7,141	—	131,198
Long-term debt, less current portion	410,000	—	—	—	410,000
Noncurrent deferred income taxes	—	174,548	—	(119,992)	54,556
Other long-term liabilities	418	2,452	227	—	3,097
Total liabilities	418,797	292,678	7,368	(119,992)	598,851
Total shareholders’ equity	406,046	654,656	49,587	(704,243)	406,046
Total liabilities and shareholders’ equity	$824,843	$947,334	$56,955	$(824,235)	$1,004,897

	December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$27,688	$(5,516)	$12,752	$—	$34,924
Receivables, net of allowance	1,641	151,048	37,512	—	190,201
Intercompany receivable (payable)	(24,836)	55,567	(30,728)	(3)	—
Deferred income taxes	1,827	8,196	975	—	10,998
Inventory	—	7,208	6,909	—	14,117
Assets held for sale	—	9,909	—	—	9,909
Prepaid expenses and other current assets	1,217	6,554	1,154	—	8,925

Total current assets	7,537	232,966	28,574	(3)	269,074
Net property and equipment	4,179	763,994	89,118	(750)	856,541
Investment in subsidiaries	830,185	116,799	—	(946,984)	—
Intangible assets, net of accumulated amortization	—	24,223	—	—	24,223
Noncurrent deferred income taxes	111,286	—	2,753	(111,286)	2,753
Other long-term assets	10,122	1,955	6,921	—	18,998
Total assets	$963,309	$1,139,937	$ 127,366	$(1,059,023)	$1,171,589
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$735	$57,910	$ 5,660	$—	$64,305
Current portion of long-term debt	—	27	—	—	27
Deferred revenues	—	3,315	—	—	3,315
Accrued expenses	11,109	64,063	4,376	(3)	79,545
Total current liabilities	11,844	125,315	10,036	(3)	147,192
Long-term debt, less current portion	455,000	53	—	—	455,053
Noncurrent deferred income taxes	138	180,726	—	(111,286)	69,578
Other long-term liabilities	513	3,658	531	—	4,702
Total liabilities	467,495	309,752	10,567	(111,289)	676,525
Total shareholders’ equity	495,814	830,185	116,799	(947,734)	495,064
Total liabilities and shareholders’ equity	$963,309	$1,139,937	$ 127,366	$(1,059,023)	$1,171,589

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	Three months ended June 30, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$120,933	$14,078	$—	$135,011
Costs and expenses:					
Operating costs	—	74,907	11,014	—	85,921
Depreciation and amortization	346	34,367	3,776	—	38,489
General and administrative	5,685	12,118	698	(138)	18,363
Intercompany leasing	—	(1,215)	1,215	—	—
Bad debt expense	—	394	—	—	394
Impairment charges	—	15,447	56,632	(750)	71,329
Gain on dispositions of property and equipment	—	(4,359)	(18)	—	(4,377)
Total costs and expenses	6,031	131,659	73,317	(888)	210,119
Income (loss) from operations	(6,031)	(10,726)	(59,239)	888	(75,108)
Other income (expense):					
Equity in earnings of subsidiaries	(70,508)	(62,574)	—	133,082	—
Interest expense	(5,135)	(118)	8	—	(5,245)
Other	(2)	419	207	(138)	486
Total other income (expense)	(75,645)	(62,273)	215	132,944	(4,759)
Income (loss) before income taxes	(81,676)	(72,999)	(59,024)	133,832	(79,867)
Income tax (expense) benefit	3,645	2,491	(3,550)	—	2,586
Net income (loss)	$(78,031)	$(70,508)	$(62,574)	$133,832	$(77,281)

	Three months ended June 30, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$234,285	$25,527	$—	$259,812
Costs and expenses:					
Operating costs	—	149,539	17,059	—	166,598
Depreciation and amortization	356	41,979	3,456	—	45,791
General and administrative	6,800	17,438	1,176	(138)	25,276
Intercompany leasing	—	(1,215)	1,215	—	—
Bad debt expense	—	561	—	—	561
Gain on dispositions of property and equipment	—	(186)	(145)	—	(331)
Total costs and expenses	7,156	208,116	22,761	(138)	237,895
Income (loss) from operations	(7,156)	26,169	2,766	138	21,917
Other income (expense):					
Equity in earnings of subsidiaries	19,707	3,512	—	(23,219)	—
Interest expense	(10,707)	(24)	3	—	(10,728)
Loss on extinguishment of debt	(14,595)	—	—	—	(14,595)
Other	7	617	1,531	(138)	2,017
Total other income (expense)	(5,588)	4,105	1,534	(23,357)	(23,306)

Income (loss) before income taxes	(12,744)	30,274	4,300	(23,219)	(1,389)
Income tax (expense) benefit	12,425	(10,567)	(788)	—	1,070
Net income (loss)	$(319)	$19,707	$3,512	$(23,219)	$(319)

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	Six months ended June 30, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$294,786	$34,039	$—	$328,825
Costs and expenses:					
Operating costs	—	190,443	26,542	—	216,985
Depreciation and amortization	695	72,044	7,532	—	80,271
General and administrative	10,760	28,373	1,366	(276)	40,223
Intercompany leasing	—	(2,430)	2,430	—	—
Bad debt expense	—	713	—	—	713
Impairment charges	—	21,437	56,632	(750)	77,319
Gain on dispositions of property and equipment	—	(3,223)	(21)	—	(3,244)
Total costs and expenses	11,455	307,357	94,481	(1,026)	412,267
Income (loss) from operations	(11,455)	(12,571)	(60,442)	1,026	(83,442)
Other income (expense):					
Equity in earnings of subsidiaries	(75,971)	(67,163)	—	143,134	—
Interest expense	(10,590)	(122)	12	—	(10,700)
Other	7	871	(2,796)	(276)	(2,194)
Total other income (expense)	(86,554)	(66,414)	(2,784)	142,858	(12,894)
Income (loss) before income taxes	(98,009)	(78,985)	(63,226)	143,884	(96,336)
Income tax (expense) benefit	7,959	3,014	(3,937)	—	7,036
Net income (loss)	$(90,050)	$(75,971)	$(67,163)	$143,884	$(89,300)

	Six months ended June 30, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$451,155	$47,691	$—	$498,846
Costs and expenses:					
Operating costs	—	290,304	31,784	—	322,088
Depreciation and amortization	625	83,843	6,849	—	91,317
General and administrative	13,535	34,636	1,864	(276)	49,759
Intercompany leasing	—	(2,430)	2,430	—	—
Bad debt expense (recovery)	—	437	—	—	437
Gain on dispositions of property and equipment	—	(1,464)	(267)	—	(1,731)
Gain on litigation	(2,876)	—	—	—	(2,876)
Total costs and expenses	11,284	405,326	42,660	(276)	458,994
Income (loss) from operations	(11,284)	45,829	5,031	276	39,852
Other income (expense):					
Equity in earnings of subsidiaries	32,592	4,087	—	(36,679)	—
Interest expense	(23,106)	(17)	7	—	(23,116)
Loss on extinguishment of debt	(22,482)	—	—	—	(22,482)
Other	10	1,288	793	(276)	1,815

Total other income (expense)	(12,986)	5,358	800	(36,955)	(43,783)
Income (loss) before income taxes	(24,270)	51,187	5,831	(36,679)	(3,931)
Income tax (expense) benefit	21,372	(18,595)	(1,744)	—	1,033
Net income (loss)	$(2,898)	$32,592	$4,087	$(36,679)	$(2,898)

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

	Six months ended June 30, 2015			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$75,207	$51,325	$(4,761)	$121,771
Cash flows from investing activities:				
Purchases of property and equipment	(268)	(82,554)	(1,205)	(84,027)
Proceeds from sale of property and equipment	22	34,487	29	34,538
Proceeds from insurance recoveries	—	227	—	227
	(246)	(47,840)	(1,176)	(49,262)
Cash flows from financing activities:				
Debt repayments	(45,000)	(2)	—	(45,002)
Debt issuance costs	(5)	—	—	(5)
Proceeds from exercise of options	753	—	—	753
Purchase of treasury stock	(711)	—	—	(711)
	(44,963)	(2)	—	(44,965)
Net increase (decrease) in cash and cash equivalents	29,998	3,483	(5,937)	27,544
Beginning cash and cash equivalents	27,688	(5,516)	12,752	34,924
Ending cash and cash equivalents	$57,686	$(2,033)	$6,815	$62,468

	Six months ended June 30, 2014			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$25,255	$57,484	$12,748	$95,487
Cash flows from investing activities:				
Purchases of property and equipment	(494)	(63,159)	(10,914)	(74,567)
Proceeds from sale of property and equipment	—	6,262	276	6,538
	(494)	(56,897)	(10,638)	(68,029)
Cash flows from financing activities:				
Debt repayments	(330,000)	(13)	—	(330,013)
Proceeds from issuance of debt	320,000	—	—	320,000
Debt issuance costs	(6,187)	—	—	(6,187)
Tender premium costs	(15,381)	—	—	(15,381)
Proceeds from exercise of options	1,581	—	—	1,581
Purchase of treasury stock	(1,132)	—	—	(1,132)
	(31,119)	(13)	—	(31,132)
Net increase (decrease) in cash and cash equivalents	(6,358)	574	2,110	(3,674)
Beginning cash and cash equivalents	28,368	(2,059)	1,076	27,385
Ending cash and cash equivalents	$22,010	$(1,485)	$3,186	$23,711

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, the continued demand for drilling services or production services in the geographic areas where we operate, decisions about exploration and development projects to be made by oil and gas exploration and production companies, the highly competitive nature of our business, technological advancements and trends in our industry and improvements in our competitors' equipment, the loss of one or more of our major clients or a decrease in their demand for our services, future compliance with covenants under our senior secured revolving credit facility and our senior notes, operating hazards inherent in our operations, the supply of marketable drilling rigs, well servicing rigs, coiled tubing and wireline units within the industry, the continued availability of drilling rig, well servicing rig, coiled tubing and wireline unit components, the continued availability of qualified personnel, the success or failure of our acquisition strategy, including our ability to finance acquisitions, manage growth and effectively integrate acquisitions, the political, economic, regulatory and other uncertainties encountered by our operations, 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, 2014, 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, 2014 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 Corp. (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 and wireline services. Through these business acquisitions, we also obtained fishing and rental services operations, which were subsequently sold on September 17, 2014. We also acquired a coiled tubing services business at the end of 2011 to expand our existing production services offerings. We have continued to invest in the growth of all our core service offerings through acquisitions and organic growth.

Pioneer Energy Services Corp. 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 two of our services (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.

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 8, 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 through our four drilling divisions in the US, and internationally in Colombia. 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 or turnkey 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.

Since October 2014, domestic and international oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. In drilling, all rig classes were severely impacted by the industry downturn. However, AC drilling rigs equipped with either a walking or skidding system are the best suited for horizontal pad drilling and are the most desirable rig design available.

During the first half of 2015, we sold 27 of our mechanical and lower horsepower electric drilling rigs. As of June 30, 2015, we continue to have three of this type of rig remaining in our fleet that are well suited for certain higher margin turnkey or horizontal drilling projects, and one rig classified as held for sale. As the downturn worsened through the first half of 2015 resulting in significantly reduced revenue and utilization rates, and as current projections reflect a more delayed recovery than previously anticipated, we performed impairment testing on all the non-AC electric drilling rigs in our fleet, including the eight drilling rigs in Colombia which are currently idle. As a result, we recognized $71.3 million of impairment charges during the second quarter of 2015, primarily to reduce the carrying values of all eight drilling rigs in Colombia and certain other assets associated with our Colombian operations, as well as the six non-AC electric drilling rigs in our domestic fleet that are not pad-capable, to their estimated fair values.

As of June 30, 2015, the drilling rigs in our fleet, excluding the one rig classified as held for sale, are assigned to the following divisions:

Drilling Division	Rig Count
South Texas	11
West Texas	4
North Dakota	8
Appalachia	4
Colombia	8
	35

In April 2015, we deployed our first of five new-build 1,500 horsepower AC drilling rigs to be delivered this year. We expect to deploy three new-build rigs in the third quarter and the final rig by the end of the year. Three of the remaining new-build drilling rigs to be deployed are under multi-year term contracts. The multi-year contract that was initially assigned to the fifth new-build drilling rig has been transferred to an existing AC rig in North Dakota that has a contract expiring in November 2015, thereby allowing us to market the fifth new-build rig to a new domestic client. Including the five new-build drilling rigs, we expect to end 2015 with a drilling fleet of 39 rigs, of which 95% will be capable of drilling horizontally, with all but one of our AC rigs built within the last five years. The removal of older, less capable rigs from our fleet and the recent and ongoing investments in the construction of new-builds is transforming our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us well to increase our market share in the significant shale basins in the US and to improve profitability.

As of June 30, 2015, 18 of our 35 drilling rigs are earning revenues under drilling contracts, 15 of which are earning under term contracts. Our eight drilling rigs in Colombia are currently idle. We are actively marketing them to various operators in Colombia to diversify our client base, and evaluating other options including the possibility of the sale of some or all of our assets in Colombia.

In response to the significant decline in oil prices during recent months, term contracts for 16 of our drilling rigs have been early terminated, including seven of our 15 drilling rigs that are currently earning revenues under term contracts, resulting in approximately $53.0 million of early termination revenues. Revenues derived from these early terminations are deferred and recognized over the remainder of the original term of the drilling contracts. We recognized $11.3 million and $16.0 million of revenue for early termination payments during the first and second quarters of 2015, respectively, and $0.3 million in the fourth quarter of 2014.

- Production Services Segment—Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing 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 June 30, 2015, we have a fleet of 110 rigs with 550 horsepower and 11 rigs with 600 horsepower with operations in 11 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota.
- 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 June 30, 2015, we have a fleet of 125 wireline units in 18 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.
- 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 June 30, 2015, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are deployed through three locations in Texas and Louisiana.

Pioneer Energy Services Corp.'s 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 through 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.

In recent years, generally increasing oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. Even though advancements in technology improved the efficiency of drilling rigs, demand remained steady, particularly for drilling rigs that are able to drill horizontally. Since October 2014, domestic and international oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. If oil prices continue to decline, or if oil and natural gas prices remain at current levels for an extended period of time, then industry equipment utilization and revenue rates could decrease further. We expect continued pricing pressure and a highly competitive environment throughout the remainder of 2015, but we believe our high-quality equipment and services are well positioned to compete.

Drilling and production services have historically trended similarly in response to fluctuations in commodity prices. However, because exploration and production companies often adjust their budgets for exploratory drilling first in response to a shift in commodity prices, the demand for drilling services is generally impacted first and to a greater extent than the demand for production services which is more dependent on ongoing expenditures that are necessary to maintain production. Additionally, within the range of production services businesses, those that derive more revenue from production related activity tend to be less affected by fluctuations in commodity prices and temporary reductions in industry activity.

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 an 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 months or years. As such, capital expenditure economics often require the use of commodity price forecasts which may prove inaccurate over the amount of time necessary to plan and execute a capital expenditure project (such as a drilling program for a number of wells in a certain area). When commodity prices are depressed for longer periods of time, capital expenditure projects are routinely deferred until prices are forecasted to 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 less dependent on commodity price forecasts.

Capital expenditures by exploration and production companies for the drilling of exploratory wells or new wells in proven areas are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices. In contrast, 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, which requires a range of production services, are relatively stable and more predictable.

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 three years are illustrated in the graphs below.

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

Colombian oil prices have historically trended in line with West Texas Intermediate (WTI) oil prices. Demand for drilling and production services in Colombia is largely dependent upon its national oil company's long-term exploration and production programs.

Technological advancements and trends in our industry also affect the demand for certain types of equipment. In recent years, and especially during the recent downturn, demand has significantly decreased for certain drilling rigs, particularly in vertical well markets. The decline is primarily due to higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling." Pad drilling enables a series of horizontal wells to be drilled in succession by a walking or skidding drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend has resulted in significantly reduced demand for drilling rigs that do not have the ability to walk or skid and to drill horizontal wells, and could further reduce the overall demand for all drilling rigs.

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, 2014.

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. By the end of 2015, we will have deployed a total of 15 new-build drilling rigs to the Bakken, Marcellus and Eagle Ford shales and the Permian Basin in the last three years. Additionally, we have added significant capacity in recent years to our production services fleets, which we believe are well positioned to further capitalize on 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. With natural gas prices at low levels in recent years, we intentionally increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions. With the recent decline in oil prices, we believe our fleets are highly capable and well positioned for deployment to whichever market is most profitable.
- Growth Through Select Capital Deployment. We have historically invested in the growth of our business by strategically upgrading our existing assets and disposing of assets which use older technology, selectively engaging in new-build opportunities, and through selective acquisitions. Since the beginning of 2010, we have added significant capacity to our production services offerings through the addition of 62 wireline units, 47 well servicing rigs and 17 coiled tubing units. We constructed ten AC drilling rigs during 2011 to 2013, and in April, we delivered the first of five new-build AC rigs which we expect to deliver and begin operating by the end of 2015. Including the five new-build drilling rigs, we expect to end 2015 with a drilling fleet of 39 rigs, of which 95% will be capable of drilling horizontally, with all but one of our AC rigs built within the last five years. The removal of older, less capable rigs from our fleet and the recent and ongoing investments in the construction of new-builds is transforming our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us well to increase our market share in the significant shale basins in the US and to improve profitability.

With the recent decline in oil prices and the expected reductions in our rig utilization and revenue rates in 2015, our near-term focus is to maintain a strong balance sheet and ample liquidity. Management efforts are focused on stringent cost control measures, the liquidation of nonstrategic or under-performing assets and continued emphasis on the execution and performance of our core businesses. We are currently executing limited organic growth through select fleet additions which were ordered prior to the recent decline in oil prices. We believe these near-term goals will position us to take advantage of future business opportunities and continue our long-term growth strategy.

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 $62.5 million as of June 30, 2015), cash generated from operations, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and the unused portion of our senior secured revolving credit facility (the “Revolving Credit Facility”).

In May 2015, 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 June 30, 2015, 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.

In March 2010 and November 2011, we issued an aggregate $425 million of unregistered senior notes with a coupon interest rate of 9.875% that were set to mature in 2018 (the “2010 and 2011 Senior Notes”). The net proceeds from the 2010 issuance were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility and a portion of the net proceeds from the 2011 issuance were used to fund the acquisition of the coiled tubing business in December 2011.

In March 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the “2014 Senior Notes”), the net proceeds from which, combined with cash on hand, were used to fund the repayment of $300 million of aggregate principal amount of 2010 and 2011 Senior Notes in March and May 2014. In October 2014, we redeemed the remaining $125.0 million in aggregate principal amount of the 2010 and 2011 Senior Notes, primarily funded by proceeds from our revolving credit facility and through cash on hand.

Our Revolving Credit Facility, as amended on September 22, 2014, 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 $350 million, all of which matures in September 2019. In addition, at our request, and with the lenders' consent, the aggregate commitments of the lenders under the Revolving Credit Facility may be increased up to an additional $100 million provided that no default exists, all representations and warranties are true and correct, and compliance with financial covenants as set forth in the Revolving Credit Facility is met immediately prior to and after giving effect thereto. As

of July 30, 2015, we had $110 million outstanding under our Revolving Credit Facility and $21.3 million in committed letters of credit, which resulted in borrowing availability of $218.7 million under our Revolving Credit Facility. There are no limitations on our ability to access this borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. 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, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and available borrowings under our Revolving Credit Facility are adequate to cover our liquidity requirements for at least the next 12 months.

Uses of Capital Resources

During the six months ended June 30, 2015, we spent $84.0 million on purchases of property and equipment and placed into service property and equipment of $95.2 million. Currently, we expect to spend approximately $160 million to $170 million on capital expenditures during 2015. We expect the total capital expenditures for 2015 will be allocated approximately 70% for our Drilling Services Segment and approximately 30% for our Production Services Segment. Our planned capital expenditures for the year ending December 31, 2015 include the remaining payments for five new-build drilling rigs, nine well servicing rigs, eight wireline units, routine capital expenditures and certain drilling equipment which was ordered in 2014 but requires a long lead-time for delivery.

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 capital expenditures in 2015 from operating cash flow in excess of our working capital requirements, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and from borrowings under our Revolving Credit Facility, if necessary.

Working Capital

Our working capital was $61.8 million at June 30, 2015, compared to $121.9 million at December 31, 2014. Our current ratio, which we calculate by dividing current assets by current liabilities, was 1.5 at June 30, 2015 compared to 1.8 at December 31, 2014.

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 new-build rig construction projects are in progress or when higher percentages of our drilling contracts are turnkey contracts.

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

	June 30, 2015	December 31, 2014	Change
Cash and cash equivalents	$62,468	$34,924	$27,544
Receivables:			
Trade, net of allowance for doubtful accounts	67,663	136,161	(68,498)
Unbilled receivables	12,635	38,002	(25,367)
Insurance recoveries	15,782	10,900	4,882
Other receivables	7,158	5,138	2,020
Deferred income taxes	5,996	10,998	(5,002)
Inventory	9,528	14,117	(4,589)
Assets held for sale	4,056	9,909	(5,853)
Prepaid expenses and other current assets	7,679	8,925	(1,246)
Current assets	192,965	269,074	(76,109)
Accounts payable	49,302	64,305	(15,003)
Current portion of long-term debt	—	27	(27)
Deferred revenues	26,113	3,315	22,798
Accrued expenses:			
Payroll and related employee costs	17,113	40,058	(22,945)
Insurance premiums and deductibles	9,501	12,829	(3,328)
Insurance claims and settlements	15,782	10,900	4,882
Interest	5,467	5,432	35
Other	7,920	10,326	(2,406)
Current liabilities	131,198	147,192	(15,994)
Working capital	$61,767	$121,882	$(60,115)

The increase in cash and cash equivalents during the six months ended June 30, 2015 is primarily due to $121.8 million of cash provided by operating activities, which includes early termination payments made on certain drilling contracts, and $34.5 million of proceeds from the sale of assets, partially offset by $84.0 million used for purchases of property and equipment and $45.0 million used for debt repayment.

The net decrease in our total trade and unbilled receivables as of June 30, 2015 as compared to December 31, 2014 is primarily the result of the decrease in consolidated revenues of $148.1 million, or 52%, for the quarter ended June 30, 2015 as compared to the quarter ended December 31, 2014.

The increase in both our insurance recoveries receivables and our insurance claims and settlements accrued expenses as of June 30, 2015 as compared to December 31, 2014 is primarily due to an increase in our insurance company's reserve for workers' compensation claims in excess of our deductibles.

The increase in other receivables as of June 30, 2015 as compared to December 31, 2014 is primarily due to a decrease in income taxes payable due to a decrease in activity for our Colombian operations, and a $0.8 million short-term note receivable related to the sale of a drilling rig during the second quarter of 2015.

The decrease in current deferred income taxes as of June 30, 2015 as compared to December 31, 2014 is primarily due to a reduction in the current deferred tax assets for our annual bonus accruals which were paid in the first quarter of 2015, as well as the valuation allowance on our Colombian deferred tax assets recognized as of June 30, 2015.

The decrease in inventory as of June 30, 2015 as compared to December 31, 2014 is primarily due to $3.6 million of impairment charges recognized in the second quarter of 2015 to reduce the carrying value of inventory associated with our Colombian operations.

As of June 30, 2015, our condensed consolidated balance sheet reflects assets held for sale of $4.1 million, which represents the fair value of one drilling rig, two wireline units, one real estate property and other drilling equipment.

The decrease in prepaid expenses and other assets as of June 30, 2015 as compared to December 31, 2014 is primarily due to a decrease in prepaid insurance costs because most of the insurance premiums are paid in late October of each year, and therefore we had amortization of eight months of these October premiums at June 30, 2015, as compared to two months at December 31, 2014.

The decrease in accounts payable as of June 30, 2015 as compared to December 31, 2014 is primarily due to the 54% decrease in our operating costs for the quarter ended June 30, 2015 as compared to the quarter ended December 31, 2014, partially offset by an increase of $11.1 million in our accruals for capital expenditures as of June 30, 2015 as compared to December 31, 2014.

The increase in deferred revenues as of June 30, 2015 as compared to December 31, 2014 is primarily related to deferred revenue for early termination payments. Revenues derived from rigs placed on standby or from the early termination of long-term drilling contracts are deferred and recognized as the amounts become fixed or determinable, over the remainder of the original term or when the rig is sold.

The decrease in accrued payroll and employee related costs as of June 30, 2015 as compared to December 31, 2014 is primarily due to a 48% reduction in headcount during the first six months of 2015.

The decrease in insurance premiums and deductibles as of June 30, 2015 as compared to December 31, 2014 is primarily due to a decrease in our workers compensation and health insurance costs resulting from a decrease in our estimated liability for the deductible under these policies.

The decrease in other accrued expenses as of June 30, 2015 as compared to December 31, 2014 is primarily due to a decrease in sales tax accruals due to the timing of payments, partially offset by $0.9 million of deposits received for the sale of the drilling rig classified as held for sale, and an increase in the Colombian equity tax obligation which was assessed in January 2015.

Long-term Debt and Other Contractual Obligations

The following table includes information about the amount and timing of our contractual obligations at June 30, 2015 (amounts in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Within 1 Year	2 to 3 Years	4 to 5 Years	Beyond 5 Years
Debt	$410,000	$—	$—	$110,000	$300,000
Interest on debt	139,972	21,059	42,118	40,045	36,750
Purchase commitments	52,412	45,012	7,400	—	—
Operating leases	13,811	4,128	5,705	3,013	965
Incentive compensation	10,920	5,626	5,294	—	—
Total	$627,115	$75,825	$60,517	$153,058	$337,715

At June 30, 2015, debt obligations consist of $300 million of principal amount outstanding under our Senior Notes and $110.0 million outstanding under our Revolving Credit Facility. The $110.0 million outstanding under our Revolving Credit Facility is due at maturity on September 22, 2019. However, we may make principal payments to reduce the outstanding balance prior to maturity when cash and working capital is sufficient. The $300 million principal amount outstanding under our 2014 Senior Notes will mature on March 15, 2022.

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 2.4% interest rate that was in effect at June 30, 2015, and (2) the outstanding balance of $110.0 million at June 30, 2015 to be paid at maturity on September 22, 2019. Interest payment obligations on our 2014 Senior Notes are calculated based on the coupon interest rate of 6.125% due semi-annually in arrears on March 15 and September 15 of each year.

Purchase commitments primarily relate to components ordered for our new-build drilling rigs, purchases of other new equipment and equipment upgrades. The total estimated cost, excluding capitalized interest, for the five new-build drilling rigs is approximately $125 million, of which $97.0 million has already been incurred, and $21.9 million of which is reflected in the purchase commitments table above. In addition, $22.5 million of the purchase commitments in the table above represent obligations for well servicing rigs and other drilling equipment that were ordered during 2014, but which require long lead-time orders.
Operating leases consist of lease agreements for office space, operating facilities, equipment and personal property.
Incentive compensation 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 $350 million borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. At June 30, 2015, we were in compliance with our financial covenants under the Revolving Credit Facility. Our total consolidated leverage ratio was 2.1 to 1.0, our senior consolidated leverage ratio was 0.6 to 1.0, and our interest coverage ratio was 7.9 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

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

The Revolving Credit Facility does not restrict capital expenditures as long as (a) no event of default exists under the Revolving Credit Facility or would result from such capital expenditures, (b) after giving effect to such capital expenditures there is availability under the Revolving Credit Facility equal to or greater than $25 million and (c) the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is less than 2.00 to 1.00. If the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is equal to or greater than 2.00 to 1.00, then capital expenditures are limited to $100 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $30 million.
At June 30, 2015, 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, 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. 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 governing our Senior Notes also contains certain restrictions which generally restrict our ability to:

- pay dividends on stock, repurchase stock, redeem subordinated indebtedness or make other restricted payments and investments;
- incur, assume or guarantee additional indebtedness or issue preferred or disqualified stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- sell or transfer assets;
- 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 any other person;
- enter into transactions with affiliates; and
- enter into new lines of business.

If we experience a change of control (as defined in the Indenture), we will be required to make an offer to each holder of the Senior Notes to repurchase all or any part of the Senior Notes at a purchase price equal to 101% of the principal amount of each Senior Note, plus accrued and unpaid interest, if any, to the date of repurchase. If we engage in certain asset sales, within 365 days of such sale we will be required to use the net cash proceeds from such sale, to the extent we do not reinvest those proceeds in our business, to make an offer to repurchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, plus accrued and unpaid interest to the repurchase date.

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. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture. In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes.

Our Senior Notes are not subject to any sinking fund requirements. As of June 30, 2015, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company, and we were in compliance with all covenants pertaining to our Senior Notes.

Results of Operations

Statements of Operations Analysis

The following table provides information about our operations for the three and six months ended June 30, 2015 and 2014 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Drilling Services Segment:				
Revenues	$58,559	$127,553	$156,974	$245,510
Operating costs	32,815	84,022	95,111	161,941
Drilling Services Segment margin	$25,744	$43,531	$61,863	$83,569
Average number of drilling rigs	37.0	62.0	41.6	62.0
Utilization rate	63 %	87 %	74 %	85 %
Revenue days	2,122	4,895	5,579	9,526
Average revenues per day	$27,596	$26,058	$28,137	$25,773
Average operating costs per day	15,464	17,165	17,048	17,000
Drilling Services Segment margin per day	$12,132	$8,893	$11,089	$8,773
Production Services Segment:				
Revenues	$76,452	$132,259	$171,851	$253,336
Operating costs	53,106	82,576	121,874	160,147
Production Services Segment margin	$23,346	$49,683	$49,977	$93,189
Combined:				
Revenues	$135,011	$259,812	$328,825	$498,846
Operating costs	85,921	166,598	216,985	322,088
Combined margin	$49,090	$93,214	$111,840	$176,758
Adjusted EBITDA	$35,196	$69,725	$71,954	$132,984

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 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 Energy Services Corp.'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 represents income (loss) before interest expense, income tax (expense) benefit, depreciation and amortization, loss on extinguishment of debt and impairments. We use this non-GAAP 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 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 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. Adjusted EBITDA may not be comparable to other similarly titled 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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(amounts in thousands)			
Reconciliation of combined margin and Adjusted EBITDA to net loss:				
Combined margin	$49,090	$93,214	$111,840	$176,758
General and administrative	(18,363)	(25,276)	(40,223)	(49,759)
Bad debt expense	(394)	(561)	(713)	(437)
Gain on dispositions of property and equipment	4,377	331	3,244	1,731
Gain on settlement of litigation	—	—	—	2,876
Other expense	486	2,017	(2,194)	1,815
Adjusted EBITDA	35,196	69,725	71,954	132,984
Depreciation and amortization	(38,489)	(45,791)	(80,271)	(91,317)
Impairment charges	(71,329)	—	(77,319)	—
Interest expense	(5,245)	(10,728)	(10,700)	(23,116)
Loss on extinguishment of debt	—	(14,595)	—	(22,482)
Income tax (expense) benefit	2,586	1,070	7,036	1,033
Net loss	$(77,281)	$(319)	$(89,300)	$(2,898)

Both our Drilling Services and Production Services Segments experienced a decline in activity during the three and six months ended June 30, 2015, as compared to the corresponding periods in 2014, due to the recent downturn in our industry. Our combined margin decreased for the three and six months ended June 30, 2015 as compared to the corresponding periods in 2014, primarily as a result of decreased activity for all our service offerings and pricing pressure in our Production Services Segment, which was partially offset by an increase in average margin per day in our Drilling Services Segment from the benefit of rigs which were earning but not working during the period and due to the removal of 28 mechanical and lower horsepower electric drilling rigs from our fleet which generally earned lower margins per day.

Our Drilling Services Segment's revenues decreased by $69.0 million, or 54%, and $88.5 million, or 36%, and our Drilling Services Segment's operating costs decreased by $51.2 million, or 61%, and $66.8 million, or 41%, for the three and six months ended June 30, 2015, respectively, as compared to the corresponding periods in 2014, primarily resulting from a decrease in revenue days and lower average operating costs per day. Revenue days decreased primarily due to the significant decrease in demand in our industry. In addition, we sold 27 mechanical and lower horsepower electric drilling rigs during the first half of 2015, and have one drilling rig classified as held for sale at June 30, 2015.

Our average revenues per day increased by 6% or $1,538 per day, and 9% or $2,364 per day, for the three and six months ended June 30, 2015, respectively, as compared to the corresponding periods in 2014. Our average revenues per day increased primarily because the drilling rigs which we removed from our fleet, as described above, were generally earning lower average revenues per day as compared to the rest of our fleet. Our average operating costs per day decreased by 10% or $1,701 per day, for the three months ended June 30, 2015, as compared to the corresponding period in 2014, primarily due to reduced costs from drilling rigs which were early terminated and are thus earning revenues while not incurring operating costs.

Demand for drilling rigs also influences the types of drilling contracts we are able to obtain. 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 2 and 16 turnkey contracts during the three and six months ended June 30, 2015, respectively, as compared to 25 and 36 turnkey drilling contracts completed during the corresponding periods in 2014,

respectively. The following table provides the percentages of our drilling revenues by drilling contract type for the three and six months ended June 30, 2015 and 2014:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Daywork contracts	100 %	94 %	96 %	96 %
Turnkey contracts	— %	6 %	4 %	4 %

Our Production Services Segment's revenues decreased by $55.8 million, or 42%, and $81.5 million, or 32%, for the three and six months ended June 30, 2015 as compared to the corresponding periods in 2014, while operating costs decreased by 36% and 24%, respectively. The decreases in our Production Services Segment's revenues and operating costs are a result of the significantly reduced demand for our services in response to the downturn in our industry, which resulted in decreased activity and increased pricing pressure for all our service offerings, especially our wireline services operations. The number of wireline jobs we completed decreased by 48% and 39% for the three and six months ended June 30, 2015, as compared to the corresponding periods in 2014. The total rig hours for our well servicing fleet decreased by 22% and 17%, for the three and six months ended June 30, 2015, as compared to the corresponding periods in 2014. Our coiled tubing utilization decreased to 24% and 29% for the three and six months ended June 30, 2015 from 53% and 52% during the corresponding periods in 2014. The decreases in revenues were partially offset by a greater mix of higher priced jobs performed in our wireline and coiled tubing businesses. The greater mix of higher cost wireline and coiled tubing jobs performed also resulted in some offsetting increase in operating costs for the three and six months ended June 30, 2015, as compared to the corresponding periods in 2014.

Our general and administrative expense decreased by approximately $6.9 million, or 27%, and $9.5 million, or 19%, for the three and six months ended June 30, 2015, respectively, as compared to the corresponding periods in 2014, primarily due to a decrease in compensation costs. The decrease in compensation expense is primarily due to a 48% reduction in our workforce during the first six months of 2015, a reduction in stock-based compensation due to a decrease in certain long-term performance-based compensation plans' actual and projected achievement levels, and reduced incentive compensation for 2015.

Our gains on disposition of assets during the six months ended June 30, 2015 are primarily related to the sale of 27 of our mechanical and lower horsepower drilling rigs. Our gains on disposition of assets during the six months ended June 30, 2014 are primarily related to the sale of our trucking assets in February 2014.

We recognized gains of $2.9 million related to settlements of litigation in our favor related to non-compete agreements during the six months ended June 30, 2014.

Our other expense of $2.2 million for the six months ended June 30, 2015 is primarily related to net foreign currency losses recognized for our Colombian operations due to the rise in the value of the U.S. dollar relative to the Colombian peso, and the net wealth tax obligation which was assessed in January 2015 by the Colombian government.

Our depreciation and amortization expenses decreased by $7.3 million and $11.0 million for the three and six months ended June 30, 2015, respectively, as compared to the corresponding periods in 2014, primarily as a result of the sales of drilling rigs and equipment during 2014 and 2015, as well as impairment charges to reduce the carrying values of certain drilling rigs to fair value as of December 31, 2014.

We recognized $77.3 million of impairment charges during the six months ended June 30, 2015, primarily to reduce the carrying values of all eight drilling rigs in Colombia and certain other assets associated with our Colombian operations, as well as the six non-AC electric drilling rigs in our domestic fleet that are not pad-capable, to their estimated fair values.

Our interest expense decreased by $5.5 million and $12.4 million for the three and six months ended June 30, 2015, respectively, as compared to the corresponding periods in 2014 due to the redemption of our 2010 and 2011 Senior Notes in 2014, which incurred interest at a higher rate than the 2014 Senior Notes which we issued in March 2014, as well as the repayments we made in 2014 and 2015 to reduce the level of debt outstanding under our Revolving Credit Facility.

Our loss on debt extinguishment during the three and six months ended June 30, 2014 represents the tender and redemption premiums and the write-off of net unamortized debt discount and debt issuance costs associated with the 2010 and 2011 Senior Notes that were redeemed in March and May 2014.

Our effective income tax rate for the six months ended June 30, 2015 was lower than the federal statutory rate in the United States primarily due to valuation allowances on Colombian deferred tax assets, the effect of foreign currency translation and the nondeductible Colombian net wealth tax.

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 or turnkey 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 contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. All of our revenues are recognized net of applicable sales taxes.

Our management has determined that it is appropriate to use the percentage-of-completion method to recognize revenue on our turnkey contracts. Although our turnkey 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 contract, we would need to rely on applicable law to enforce our lien rights, because our turnkey 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 contract.

The risks to us under a turnkey contract 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 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 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.
With most long-term drilling contracts, we are entitled to receive a full or reduced rate of revenue from our clients if they choose to place a rig on standby or to early terminate the contract before its original expiration term. Generally, these revenues are billed and collected over the remaining term of the contract, as the rig is placed on standby rather than fully released from the contract, and thus may go back to work at the client's decision any time before the end of the contract. Some of our drilling contracts contain "make-whole" provisions whereby if we are able to secure additional work for the rig with another client, then each party is entitled to a make-whole payment. If the dayrates under the new contract are less than the dayrates in the original contract, we would be entitled to a reduced revenue dayrate from the terminating client, and likewise, the terminating client may be entitled to a payment from us if the new contract dayrates exceed those of the original contract. A client may also choose to early terminate the contract and make an upfront early termination payment based on a per day rate for the remaining term of the contract. Revenues derived from rigs placed on standby or from the early termination of long-term drilling contracts are deferred and recognized as the amounts become fixed or determinable, over the remainder of the original term or when the rig is sold.
Our Production Services Segment earns revenues for well servicing, wireline services and coiled tubing services pursuant to master services agreements based on purchase orders, contracts or other arrangements with the client that include fixed or determinable prices. Production services jobs are generally short-term and are charged at current market rates. Production service revenue is recognized when the service has been rendered and collectability is reasonably assured.
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. 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 and coiled tubing). For our Drilling Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for individual domestic drilling rig assets and for our Colombian drilling rig assets as a group. 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.
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 1 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 expenses, our estimates of projected cash flows and fair values 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 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 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 contracts takes such risks into consideration. We are more likely to encounter losses on turnkey 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 contracts has historically exceeded our profitability on daywork contracts.

We incurred a total loss of $0.5 million on three of the 16 turnkey contracts which were completed during the six months ended June 30, 2015, and we incurred a total loss of $0.8 million on five of the 36 turnkey contracts completed during the six months ended June 30, 2014.

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 $2.7 million at June 30, 2015.

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 1 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 45 years of experience in the oilfield services industry with similar equipment.

We evaluate for potential impairment of long-lived tangible and intangible assets subject to amortization when indicators of impairment are present. Since October 2014, domestic and international oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. As the downturn worsened through the first half of 2015 resulting in significantly reduced revenue and utilization rates, and as current projections reflect a more delayed recovery than previously anticipated, we performed impairment testing on all the non-AC electric drilling rigs in our fleet, including the eight drilling rigs in Colombia which are currently idle. We also performed an impairment test on our coiled tubing operations, which have a net book value of $90.0 million at June 30, 2015.

In order to estimate our future undiscounted cash flows from the use and eventual disposition of our drilling assets, we incorporated probabilities of selling these assets in the near term, versus working them at a significantly reduced expected rate of utilization through the end of their remaining useful lives. The most significant assumptions used in our analysis are the expected margin per day and utilization, as well as the estimated proceeds upon any future sale or disposal of the assets. 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.

Our analysis indicated that the carrying value of our coiled tubing reporting unit was recoverable and thus there was no impairment present at June 30, 2015. Our analysis indicated that there was no impairment present for the pad-capable non-AC drilling rigs in our fleet (those that are equipped with either a walking or skidding system). However, our analysis indicated that the carrying values of the non-AC drilling rigs in our domestic fleet which are not pad-capable, and our Colombian assets as a group, exceeded our estimated undiscounted cash flows for these assets. As a result, we recorded $69.8 million of impairment charges during the second quarter of 2015 to reduce the carrying values of these assets to their estimated fair values, based on market appraisals which are considered Level 3 inputs as defined by ASC Topic 820, Fair Value Measurements and Disclosures. We also recognized $1.5 million of impairment charges during the second quarter of 2015 to reduce the carrying values of assets which were classified as held for sale, to their estimated fair values, based on expected sales prices.

These impairment charges are not expected to have an impact on our liquidity or debt covenants; however, they are a reflection of the overall downturn in our industry and decline in our projected future cash flows. If the demand for our drilling services remains at current levels or declines further and any of our rigs become or remain idle for an extended amount of time, then our estimated cash flows may further decrease, and the probability of a near term sale may increase. If any of the foregoing were to occur, we may incur additional impairment charges.

As of June 30, 2015, we had $80.7 million of deferred tax assets related to domestic and foreign net operating losses that are 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 domestic 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. However, as a result of the conditions leading to the impairment of our drilling rigs and other assets related to our Colombian operations, we recorded a valuation allowance of $21.1 million as of June 30, 2015 that fully offsets our foreign deferred tax assets relating to net operating losses and other tax benefits.

Our accrued insurance premiums and deductibles as of June 30, 2015 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $2.1 million and our workers’ compensation, general liability and auto liability insurance of approximately $7.0 million. We have stop-loss coverage of $200,000 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.

Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, a comprehensive new revenue recognition standard that will supersede nearly all existing revenue recognition guidance. The standard outlines a single comprehensive model for revenue recognition based on the core principle that a company will recognize revenue when promised goods or services are transferred to clients, in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. We are required to apply this new standard beginning with our first quarterly filing in 2017. In July 2015, the FASB decided to defer the effective date by one year (until

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2018), but the FASB still needs to issue an ASU to change the effective date. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this new standard will have a material effect on our financial position or results of operations.

Debt Issuance Costs. On April 7, 2015, the FASB issued Accounting Standards Update ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and will be effective for us beginning with our first quarterly filing in 2016. Early adoption is permitted. We do not expect this adoption to have a material impact on our financial position or results of operations.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

We are subject to interest rate market risk on our variable rate debt. As of June 30, 2015, we had $110.0 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 $0.6 million, and a corresponding increase or decrease, respectively, in net income of approximately $0.4 million during the six months ended June 30, 2015. 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, 2015.

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 have 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 $1.7 million for the six months ended June 30, 2015.

Item 4. Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2015, to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the three months ended June 30, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Not applicable.

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

We did not make any unregistered sales of equity securities during the quarter ended June 30, 2015. The following table provides information relating to our repurchase of common shares during the quarter ended June 30, 2015:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share (2)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
April 1—April 30	38,589	$ 7.44	—	—
May 1—May 31	—	$ —	—	—
June 1—June 30	9,464	$ 6.84	—	—
Total	48,053	$ 7.32	—	—

(1) The shares indicated consist of shares of our common stock tendered by employees to the Company during the three months ended June 30, 2015, to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock unit awards, which we repurchased based on the fair market value on the date the relevant transaction occurred.

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

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

The following 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, by and 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)).
4.7*	-	Indenture, dated March 18, 2014, by and among Pioneer Energy Services Corp., the subsidiaries named as guarantors therein and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 18, 2014 (File No. 1-8182, Exhibit 4.1)).
4.8*	-	Registration Rights Agreement, dated March 18, 2014, by and among Pioneer Energy Services Corp., the subsidiaries named as guarantors therein and the initial purchasers party thereto (Form 8-K dated March 18, 2014 (File No. 1-8182, Exhibit 10.1)).
10.1+**	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement.
10.2+**	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement.
10.3+**	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Restricted Stock Unit Award Agreement.
10.4+**	-	

		Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Restricted Stock Unit Award Agreement.
10.5+**	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Non-Employee Director Restricted Stock Award Agreement.
10.6+**	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Cash Award Agreement.
31.1**	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2**	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32.1#	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2#	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101**	-	The following financial statements from Pioneer Energy Services Corp.'s Form 10-Q for the quarter ended June 30, 2015, 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.
\+ Management contract or compensatory plan or arrangement.

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: July 30, 2015

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