PIONEER ENERGY SERVICES CORP
Form 10-Q
April 29, 2016

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 March 31, 2016
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	74-2088619
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
1250 NE Loop 410, Suite 1000 San Antonio, Texas	78209
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (855) 884-0575
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

As of April 15, 2016, there were 64,684,509 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

	March 31, 2016 (unaudited)		December 31, 2015 (audited)	
	(in thousands, except share data)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	18,669	$	14,160
Receivables:				
Trade, net of allowance for doubtful accounts	42,227		47,577	
Unbilled receivables	4,144		13,624	
Insurance recoveries	15,196		14,556	
Other receivables	3,856		4,059	
Inventory	8,501		9,262	
Assets held for sale	4,276		4,619	
Prepaid expenses and other current assets	6,678		7,411	
Total current assets	103,547		115,268	
Property and equipment, at cost	1,149,158		1,146,994	
Less accumulated depreciation	469,890		444,409	
Net property and equipment	679,268		702,585	
Intangible assets, net of accumulated amortization of $12.3 million at both March 31, 2016 and December 31, 2015	1,551		1,944	
Deferred income taxes	22		18	
Other long-term assets	2,137		2,178	
Total assets	$	786,525	$	821,993
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	12,966	$	16,951
Deferred revenues	7,878		6,222	
Accrued expenses:				
Payroll and related employee costs	14,346		13,859	
Insurance premiums and deductibles	6,676		8,087	
Insurance claims and settlements	15,196		14,556	

Interest	919	5,508
Other	4,459	4,859
Total current liabilities	62,440	70,042
Long-term debt, less debt issuance costs	387,621	387,217
Deferred income taxes	16,288	17,520
Other long-term liabilities	5,064	4,571
Total liabilities	471,413	479,350
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; 64,684,509 and 64,497,915 shares outstanding at March 31, 2016 and December 31, 2015, respectively	6,517	6,496
Additional paid-in capital	476,013	475,823
Treasury stock, at cost; 489,754 and 458,170 shares at March 31, 2016 and December 31, 2015, respectively	(3,802)	(3,759)
Accumulated deficit	(163,616)	(135,917)
Total shareholders’ equity	315,112	342,643
Total liabilities and shareholders’ equity	$ 786,525	$ 821,993

See accompanying notes to condensed consolidated financial statements.

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

	Three months ended March 31,	
	2016	2015
	(in thousands, except per share data)	
Revenues:		
Drilling services	$33,184	$98,415
Production services	41,768	95,399
Total revenues	74,952	193,814
Costs and expenses:		
Drilling services	17,440	62,295
Production services	34,849	68,769
Depreciation and amortization	29,824	41,782
General and administrative	16,508	21,860
Bad debt expense (recovery)	(55)	319
Impairment charges	—	5,990
Loss (gain) on dispositions of property and equipment, net	(600)	1,133
Total costs and expenses	97,966	202,148
Loss from operations	(23,014)	(8,334)
Other (expense) income:		
Interest expense, net of interest capitalized	(6,254)	(5,455)
Other	(389)	(2,680)
Total other expense	(6,643)	(8,135)
Loss before income taxes	(29,657)	(16,469)
Income tax benefit	1,958	4,450
Net loss	$(27,699)	$(12,019)
Loss per common share—Basic	$(0.43)	$(0.19)
Loss per common share—Diluted	$(0.43)	$(0.19)
Weighted average number of shares outstanding—Basic	64,576	63,991
Weighted average number of shares outstanding—Diluted	64,576	63,991

See accompanying notes to condensed consolidated financial statements.

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

	Three months ended March 31,	
	2016	2015
	(in thousands)	
Cash flows from operating activities:		
Net loss	$(27,699)	$(12,019)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	29,824	41,782
Allowance for doubtful accounts, net of recoveries	(55)	319
(Gain) loss on dispositions of property and equipment, net	(600)	1,133
Stock-based compensation expense	1,177	405
Amortization of debt issuance costs, discount and premium	424	413
Impairment charges	—	5,990
Deferred income taxes	(2,201)	(5,403)
Change in other long-term assets	15	440
Change in other long-term liabilities	492	503
Changes in current assets and liabilities:		
Receivables	13,189	40,274
Inventory	629	431
Prepaid expenses and other current assets	734	1,615
Accounts payable	(2,684)	(19,429)
Deferred revenues	1,656	30,605
Accrued expenses	(5,274)	(22,178)
Net cash provided by operating activities	9,627	64,881
Cash flows from investing activities:		
Purchases of property and equipment	(5,532)	(45,675)
Proceeds from sale of property and equipment	477	6,276
Proceeds from insurance recoveries	—	37
Net cash used in investing activities	(5,055)	(39,362)
Cash flows from financing activities:		
Debt repayments	—	(25,002)
Debt issuance costs	(20)	(5)
Proceeds from exercise of options	—	601
Purchase of treasury stock	(43)	(359)
Net cash used in financing activities	(63)	(24,765)
Net increase in cash and cash equivalents	4,509	754
Beginning cash and cash equivalents	14,160	34,924
Ending cash and cash equivalents	$18,669	$35,678
Supplementary disclosure:		
Interest paid	$10,606	$10,347
Income tax paid	$279	$664
Noncash investing and financing activity:		

Change in capital expenditure accruals	$(39)	$3,141

See accompanying notes to condensed consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
1. Organization and Summary of Significant Accounting Policies
Business
Pioneer Energy Services Corp. provides land-based drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies in 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. We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. The drilling rigs in our fleet are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	6
West Texas	7
North Dakota	6
Appalachia	4
Colombia	8
	31

Our Production Services Segment provides a range of services to a diverse group of exploration and production companies, with our operations 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 March 31, 2016, our production services fleets are as follows:
Production Services Fleets

	550 HP	600 HP	Total
Well servicing rigs, by horsepower (HP) rating	114	11	125

	Offshore	Onshore	Total
Wireline units	6	119	125
Coiled tubing units	5	12	17

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.
With most 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 often 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 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.

Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. As a result, term contracts for 19 of our drilling rigs were terminated early, including three which were terminated in early 2016, and resulting in a total of $62.8 million of early termination payments. We recognized $49.2 million and $0.3 million of revenue for early termination payments during the years ended December 31, 2015 and 2014, respectively. We recognized $7.1 million during the first quarter of 2016 and we will recognize the remaining $6.2 million during the second and third quarters of 2016.

Currently, 13 of our 23 domestic drilling rigs are earning revenues, 10 of which are under term contracts. Of the eight rigs in Colombia, three are under term contracts, but have been put on standby by our client and are not earning revenue. The term contracts in Colombia are cancelable without penalty, by our client if 30 days' notice is provided, and by us if rig operations are suspended without an associated dayrate. We are actively marketing our idle drilling rigs in Colombia to various operators to diversify our client base, and evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

Including these three contracts in Colombia, 16 of our drilling rigs are currently under contract, which if not canceled or renewed prior to the end of their terms, will expire as follows:

	Spot Market Contracts	Term Contracts and Term Contract Expiration by Period					
		Total Term Contracts	Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years	2 to 4 Years
Domestic Rigs:							
Earning under contract	3	8	2	1	—	2	3
Earning but not working	—	2	2	—	—	—	—
Colombia Rigs (on standby)	—	3	1	—	—	—	2
	3	13	5	1	—	2	5

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements include the accounts of Pioneer Energy Services Corp. and our wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of our management, all adjustments (consisting of normal, recurring accruals) necessary for a fair presentation have been included. We suggest that you read these 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, 2015.

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 the valuation allowance for deferred tax assets, 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 March 31, 2016, 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 $4.1 million at March 31, 2016, of which $3.3 million represented revenue recognized but not yet billed on daywork drilling contracts in progress and $0.8 million related to unbilled receivables for our Production Services Segment. At December 31, 2015, our unbilled receivables totaled $13.6 million, of which $11.9 million represented revenue recognized but not yet billed on daywork drilling contracts in progress, $1.1 million related to unbilled receivables for our Production Services Segment, and $0.6 million related to one turnkey contract in progress.

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.

Other Long-Term Assets

Other long-term assets consist of cash deposits related to the deductibles on our workers’ compensation insurance policies, deferred compensation plan investments 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, and 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, the long-term portion of deferred revenues, deferred lease liabilities and other deferred liabilities.

Related-Party Transactions

During the three months ended March 31, 2016 and 2015, the Company paid approximately $24,000 and $7,000, respectively, for trucking and equipment rental services, which represented arms-length transactions, to Gulf Coast Lease Service. Joe Freeman, our Senior Vice President of Well Servicing, serves as the President of Gulf Coast Lease Service, 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.

Comprehensive Income

We have not reported comprehensive income due to the absence of items of other comprehensive income in the years presented.

Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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 2018. 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 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, and that amortization of debt issuance costs be reported as interest expense. In August 2015, these provisions were further amended with guidance from the Securities and Exchange Commission Staff that they would not object to an entity deferring and presenting debt issuance costs related to line-of-credit arrangements as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and is effective for us beginning with our first quarterly filing in 2016. The adoption of this new standard resulted in reclassifying $7.8 million of debt issuance costs from other long-term assets to long-term debt in the accompanying December 31, 2015 condensed consolidated balance sheet.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases, which among other things, requires lessees to recognize substantially all leases on the balance sheet, with expense recognition that is similar to the current lease standard, and aligns the principles of lessor accounting with the principles of the FASB's new revenue guidance (referenced above). This ASU is effective for us beginning with our first quarterly filing in 2019. We are currently evaluating the potential impact of this guidance and have not yet determined its impact on our financial position and results of operations.

Stock-Based Compensation. In March 2016, the FASB issued ASU No. 2016-09, Stock Compensation: Improvements to Employee Share-Based Payment Accounting, to reduce complexity in accounting standards involving several aspects of the accounting for employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This ASU is effective for us beginning with our first quarterly filing in 2017. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this update will have a material effect 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 three months ended March 31, 2016 and 2015, we had capital expenditures of $5.5 million and $48.8 million, respectively, which includes $0.2 million and $0.7 million, respectively, of capitalized interest costs incurred during the construction periods of new drilling rigs and other drilling equipment. Capital expenditures during 2015 primarily related to our five drilling rigs which began construction during 2014, as well as unit additions to our production services fleets. As of March 31, 2016 and December 31, 2015, capital expenditures incurred for property and equipment not yet placed in service was $16.7 million and $18.6 million, respectively, primarily related to drilling equipment which will be put into service when we receive the final components that are currently on order, but which require a long lead-time for delivery.

During the three months ended March 31, 2016, we recorded net gains of $0.6 million on the disposition of property and equipment, primarily excess drill pipe. During the three months ended March 31, 2015, we recorded net losses of $1.1 million on the disposition of property and equipment, primarily for the sale of 20 of our mechanical and lower horsepower electric drilling rigs and other drilling equipment which we sold in March 2015 for aggregate proceeds of $23.3 million, $17.2 million of which was recognized as a receivable at March 31, 2015.

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 determine the fair value of the asset group. The amount of an impairment charge is measured as the difference between the carrying amount and the fair value of the assets. The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment.

During the three months ended March 31, 2015, we recorded impairment charges of $6.0 million to reduce the carrying value of certain assets which were classified as held for sale, to their estimated fair values, based on expected sales prices. As of March 31, 2016, our condensed consolidated balance sheet reflects assets held for sale of $4.3 million, which primarily represents the fair value of four drilling rigs and other equipment.

3. Valuation Allowances on Deferred Tax Assets

As of March 31, 2016, we had $99.3 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 consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

In performing this analysis as of March 31, 2016 in accordance with ASC Topic 740, Income Taxes, we assessed the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ending December 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as projections for taxable income in future years. Due to the continued downturn in our industry, we expect to be in a net deferred tax asset position by the end of 2016, and as a result, we may recognize a benefit only to the extent that reversals of deferred income tax liabilities are expected to generate income tax expense in each relevant jurisdiction in future periods which would offset our deferred tax assets.

Our 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 2030, with the latest expiration in 2033. However, we determined that a valuation allowance should be recorded against some of the benefit expected to be generated in 2016. The valuation allowance has been factored into the estimated annual tax rate to be applied throughout 2016, and is the primary factor causing our effective tax rate to be significantly lower than the statutory rate of 35%. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as projected future taxable income.

The foreign net operating losses have an indefinite carryforward period. However, as a result of the conditions leading to the impairment of our assets in Colombia during 2015 and the continued industry downturn, we have a valuation allowance that fully offsets our $17.3 million of foreign deferred tax assets at March 31, 2016.

4. Debt

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

	March 31, 2016	December 31, 2015
Senior secured revolving credit facility	$95,000	$ 95,000
Senior notes	300,000	300,000
	395,000	395,000
Less unamortized debt issuance costs	(7,379)	(7,783)
	$387,621	$ 387,217

Senior Secured Revolving Credit Facility

We have a credit agreement, as amended on September 15, 2015 and again on December 23, 2015, 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 $200 million, subject to availability under a borrowing base comprised of certain eligible cash, certain eligible receivables, certain eligible inventory, and certain eligible equipment of ours and certain of our subsidiaries, all of which matures in March 2019 (the “Revolving Credit Facility”). The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and cash-collateralize letter of credit exposure, but in no event will reduce the borrowing availability under the Revolving Credit Facility to the lesser of $200 million and the then-applicable borrowing base.

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 of 4.75% and 3.75%, respectively. The Revolving Credit Facility requires a commitment fee due quarterly based on the average daily unused amount of the commitments of the lenders, a fronting fee due for each letter of credit issued, and a quarterly letter of credit fee due based on the average undrawn amount of letters of credit outstanding during such period. Additionally, the Revolving Credit Facility requires that if on the last business day of the calendar month, our aggregate amount of cash exceeds $25 million, we pay down the outstanding principal balance by the amount of such excess.

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 March 31, 2016, we had $95 million outstanding under our Revolving Credit Facility and $17.3 million in committed letters of credit, which resulted in borrowing availability of $87.7 million under our Revolving Credit Facility. There are no limitations on our ability to access the 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 March 31, 2016, we were in compliance with our financial covenants under the Revolving Credit Facility. Our senior consolidated leverage ratio was 1.3 to 1.0 and our interest coverage ratio was 3.9 to 1.0.

The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum senior consolidated leverage ratio, calculated as senior consolidated debt at the period end, which excludes unsecured and subordinated debt, divided by EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility. The senior consolidated leverage ratio cannot exceed the following maximum amounts as follows:

3.00	to 1.00	on	March 31, 2016
3.50	to 1.00	on	June 30, 2016
4.25	to 1.00	on	September 30, 2016
4.75	to 1.00	on	December 31, 2016
4.75	to 1.00	on	March 31, 2017
4.75	to 1.00	on	June 30, 2017
4.25	to 1.00	on	September 30, 2017
3.50	to 1.00	on	December 31, 2017
3.50	to 1.00	on	March 31, 2018
3.25	to 1.00	on	June 30, 2018
2.50	to 1.00	at any time after June 30, 2018	

- A minimum interest coverage ratio, calculated as EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility, divided by interest expense for the same period. The interest coverage ratio cannot be less than the following minimum amounts as follows:

1.50	to 1.00	for each quarterly period ending March 31, 2016 through June 30, 2016
1.25	to 1.00	for each quarterly period ending September 30, 2016 through September 30, 2017
1.50	to 1.00	at any time after September 30, 2017

The Revolving Credit Facility also does not restrict capital expenditures as long as (a) no event of default under the Revolving Credit Facility exists or would result from such expenditures, and (b) such expenditures do not cause total capital expenditures to exceed $50 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 $25 million.

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, repurchases of capital stock, 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

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Senior Notes in March and May 2014. In October 2014, we redeemed the remaining $125 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.

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 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 March 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. We recognized $0.4 million of associated amortization during each of the three months ended March 31, 2016 and 2015.

5. Fair Value of Financial Instruments

The FASB's Accounting Standards Codification (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 March 31, 2016 and December 31, 2015, 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 March 31, 2016 and December 31, 2015 (amounts in thousands):

	March 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	$387,621	$225,675	$387,217	$242,354

6. Earnings Per Common Share

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

	Three months ended March 31,	
	2016	2015
Numerator (both basic and diluted):		
Net loss	$(27,699)	$(12,019)
Denominator:		
Weighted-average shares (denominator for basic earnings per share)	64,576	63,991
Diluted effect of outstanding stock options, restricted stock and restricted stock unit awards	—	—
Denominator for diluted earnings per share	64,576	63,991
Loss per common share—Basic	$(0.43)	$(0.19)
Loss per common share—Diluted	$(0.43)	$(0.19)
Potentially dilutive securities excluded as anti-dilutive	5,909	5,105

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 March 31, 2016, 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 grant restricted stock unit awards with vesting based on time of service conditions, and in certain cases, subject to performance and market conditions. In 2016, we granted phantom stock unit awards with vesting based on time of service, performance and market conditions, which were classified as liability awards under ASC Topic 718, Compensation—Stock Compensation since we expect to settle the awards in cash when they become vested. We recognize compensation cost for stock option, restricted stock, restricted stock unit, and phantom stock unit awards based on the fair value estimated in accordance with ASC Topic 718. 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 stock-based compensation expense recognized for stock option, restricted stock and restricted stock unit awards, and the compensation expense recognized for phantom stock unit awards during the three months ended March 31, 2016 and 2015 (amounts in thousands):

	Three months ended March 31,	
	2016	2015
Stock option awards	$193	$264
Restricted stock awards	87	124
Restricted stock unit awards	897	17
	$1,177	$405
Phantom stock unit awards	$118	$—

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 March 31, 2016 or 2015. The following table summarizes the assumptions used in the Black-Scholes option pricing model based on a weighted-average calculation for the three months ended March 31, 2016 and 2015:

	Three months ended March 31,			
	2016		2015	
Expected volatility	70	%	64	%
Risk-free interest rates	1.5	%	1.4	%
Expected life in years	5.70		5.52	
Options granted	905,966		341,638	
Grant-date fair value	$0.80		$2.31	

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 months ended March 31, 2016, no stock options were exercised. During the three months ended March 31, 2015, 156,500 stock options were exercised at a weighted-average exercise price of $3.84. 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, when we have excess tax benefits resulting from the exercise of stock options, we report them as financing cash flows in our condensed consolidated statement of cash flows, unless otherwise disallowed under ASC Topic 740, Income Taxes.

Restricted Stock

We grant restricted stock awards that vest over a one-year period with a fair value based on the closing price of our common stock on the date of the grant. When restricted stock awards are granted, or when restricted stock unit awards are converted to restricted stock, shares of our common stock are considered issued, but subject to certain restrictions. We did not grant any restricted stock awards during the three months ended March 31, 2016 or 2015.

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.

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 March 31, 2016 and 2015:

	Three months ended March 31,	
	2016	2015
Time-based RSUs:		
Time-based RSUs granted	231,834	451,919
Weighted-average grant-date fair value	$1.31	$ 4.08
Performance-based RSUs:		
Performance-based RSUs granted	—	294,666
Weighted-average grant-date fair value	$—	$ 4.49

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 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 2016, we determined that 72.1% of the target number of shares granted during 2013 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, 2013 through December 31, 2015. The performance-based RSUs granted during 2013 vested and were converted to common stock at the end of April 2016. As of March 31, 2016, we estimated that our actual achievement level for the performance-based RSUs granted during 2014 and 2015 will be approximately 80% and 100% of the predetermined performance conditions, respectively.

Phantom Stock Unit Awards

In 2016, we granted 1,268,068 phantom stock unit awards that cliff-vest after 39 months from the date of grant, with vesting based on time of service, performance and market conditions. The number of units ultimately awarded will be based upon the Company's achievement in certain performance conditions, as compared to a predefined peer group, over the three-year performance period, and each unit awarded will entitle the employee to a cash payment equal to the stock price of our common stock on the date of vesting, subject to a maximum of four times the stock price on the date of grant.

These awards are classified as liability awards under ASC Topic 718, Compensation—Stock Compensation, because we expect to settle the awards in cash when they vest, and are remeasured at fair value at each reporting period until they vest. Approximately half of the phantom stock unit awards granted 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. The remaining phantom stock unit awards 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 of these awards is measured using a Black-Scholes pricing model.

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 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, including well servicing, wireline services and coiled tubing services, to a diverse group of exploration and production companies, with our operations 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 months ending March 31, 2016 and 2015 (amounts in thousands):

	As of and for the three months ended March 31, 2016			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$495,442	$270,741	$20,342	$786,525
Revenues	$33,184	$41,768	$—	$74,952
Operating costs	17,440	34,849	—	52,289
Segment and combined margin	$15,744	$6,919	$—	$22,663
Depreciation and amortization	$15,678	$13,814	$332	$29,824
Capital expenditures	$2,108	$3,289	$96	$5,493

	As of and for the three months ended March 31, 2015			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$687,719	$435,295	$ 836	$1,123,850
Revenues	$98,415	$95,399	$ —	$193,814
Operating costs	62,295	68,769	—	131,064
Segment and combined margin	$36,120	$26,630	$ —	$62,750
Depreciation and amortization	$23,600	$17,833	$ 349	$41,782
Capital expenditures	$33,056	$15,457	$ 303	$48,816

The following table reconciles the combined margin reported above to income from operations as reported on the consolidated statements of operations for the three months ended March 31, 2016 and 2015 (amounts in thousands):

	Three months ended March 31,	
	2016	2015
Combined margin	$22,663	$62,750
Depreciation and amortization	(29,824)	(41,782)
General and administrative	(16,508)	(21,860)
Bad debt (expense) recovery	55	(319)
Impairment charges	—	(5,990)
Gain (loss) on dispositions of property and equipment, net	600	(1,133)
Loss from operations	$(23,014)	$(8,334)

The following table sets forth certain financial information for our international operations in Colombia as of and for the three months ended March 31, 2016 and 2015 (amounts in thousands):

	As of and for the three months ended March 31,	
	2016	2015
Identifiable assets	$48,729	$135,184
Revenues	$1,096	$19,961

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. Due to the downturn in our industry and the resulting loss of drilling contracts, we recognized impairment charges of $60.2 million in 2015 to reduce the carrying values of all eight drilling rigs in Colombia and related drilling equipment, as well as inventory and nonrecoverable prepaid taxes associated with our Colombian operations.

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 $39.2 million relating to our performance under these bonds as of March 31, 2016.

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 March 31, 2016, 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)

	March 31, 2016				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$15,782	$152	$2,735	$—	$18,669
Receivables, net of allowance	16	56,590	8,817	—	65,423
Intercompany receivable (payable)	(24,836)	31,628	(6,792)	—	—
Inventory	—	4,854	3,647	—	8,501
Assets held for sale	—	4,276	—	—	4,276
Prepaid expenses and other current assets	1,089	4,038	1,551	—	6,678
Total current assets	(7,949)	101,538	9,958	—	103,547
Net property and equipment	3,075	645,879	30,314	—	679,268
Investment in subsidiaries	626,699	37,358	—	(664,057)	—
Intangible assets, net of accumulated amortization	—	1,551	—	—	1,551
Deferred income taxes	85,921	—	22	(85,921)	22
Other long-term assets	392	893	852	—	2,137
Total assets	$708,138	$787,219	$41,146	$(749,978)	$786,525
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$516	$11,693	$757	$—	$12,966
Deferred revenues	—	7,350	528	—	7,878
Accrued expenses	3,848	35,754	1,994	—	41,596
Total current liabilities	4,364	54,797	3,279	—	62,440
Long-term debt, less debt issuance costs	387,621	—	—	—	387,621
Deferred income taxes	—	102,209	—	(85,921)	16,288
Other long-term liabilities	1,041	3,514	509	—	5,064
Total liabilities	393,026	160,520	3,788	(85,921)	471,413
Total shareholders' equity	315,112	626,699	37,358	(664,057)	315,112
Total liabilities and shareholders' equity	$708,138	$787,219	$41,146	$(749,978)	$786,525

	December 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$17,221	$(5,612)	$2,551	$—	$14,160
Receivables, net of allowance	74	67,174	12,568	—	79,816
Intercompany receivable (payable)	(24,836)	31,108	(6,272)	—	—
Inventory	—	5,591	3,671	—	9,262
Assets held for sale	—	4,619	—	—	4,619
Prepaid expenses and other current assets	1,200	4,767	1,444	—	7,411
Total current assets	(6,341)	107,647	13,962	—	115,268
Net property and equipment	3,311	667,321	31,953	—	702,585
Investment in subsidiaries	657,090	42,240	—	(699,330)	—
Intangible assets, net of accumulated amortization	—	1,944	—	—	1,944

Deferred income taxes	84,989	—	18	(84,989)	18
Other long-term assets	512	962	704	—	2,178
Total assets	$739,561	$ 820,114	$ 46,637	$ (784,319)	$ 821,993
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$616	$ 14,628	$ 1,707	$ —	$ 16,951
Deferred revenues	—	5,570	652	—	6,222
Accrued expenses	8,373	37,023	1,473	—	46,869
Total current liabilities	8,989	57,221	3,832	—	70,042
Long-term debt, less debt issuance costs	387,217	—	—	—	387,217
Deferred income taxes	—	102,509	—	(84,989)	17,520
Other long-term liabilities	712	3,294	565	—	4,571
Total liabilities	396,918	163,024	4,397	(84,989)	479,350
Total shareholders' equity	342,643	657,090	42,240	(699,330)	342,643
Total liabilities and shareholders' equity	$739,561	$ 820,114	$ 46,637	$ (784,319)	$ 821,993

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(unaudited, in thousands)

	Three months ended March 31, 2016				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 73,856	$ 1,096	$ —	$ 74,952
Costs and expenses:					
Operating costs	—	50,310	1,979	—	52,289
Depreciation and amortization	332	27,731	1,761	—	29,824
General and administrative	5,885	10,548	213	(138)	16,508
Bad debt expense (recovery)	—	(55)	—	—	(55)
Loss (gain) on dispositions of property and equipment, net	—	(555)	(45)	—	(600)
Intercompany leasing	—	(1,215)	1,215	—	—
Total costs and expenses	6,217	86,764	5,123	(138)	97,966
Income (loss) from operations	(6,217)	(12,908)	(4,027)	138	(23,014)
Other income (expense):					
Equity in earnings of subsidiaries	(16,417)	(4,846)	—	21,263	—
Interest expense, net of interest capitalized	(6,234)	(22)	2	—	(6,254)
Other	(7)	320	(564)	(138)	(389)
Total other (expense) income	(22,658)	(4,548)	(562)	21,125	(6,643)
Income (loss) before income taxes	(28,875)	(17,456)	(4,589)	21,263	(29,657)
Income tax (expense) benefit [1]	1,176	1,039	(257)	—	1,958
Net income (loss)	$(27,699)	$ (16,417)	$ (4,846)	$ 21,263	$ (27,699)

	Three months ended March 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 173,853	$ 19,961	$ —	$ 193,814
Costs and expenses:					
Operating costs	—	115,539	15,525	—	131,064
Depreciation and amortization	349	37,677	3,756	—	41,782
General and administrative	5,075	16,255	668	(138)	21,860
Bad debt expense (recovery)	—	319	—	—	319
Impairment charges	—	5,990	—	—	5,990
Loss (gain) on dispositions of property and equipment, net	—	1,133	—	—	1,133
Intercompany leasing	—	(1,215)	1,215	—	—
Total costs and expenses	5,424	175,698	21,164	(138)	202,148
Income (loss) from operations	(5,424)	(1,845)	(1,203)	138	(8,334)
Other income (expense):					
Equity in earnings of subsidiaries	(5,463)	(4,589)	—	10,052	—
Interest expense, net of interest capitalized	(5,455)	(4)	4	—	(5,455)
Other	9	452	(3,003)	(138)	(2,680)
Total other (expense) income	(10,909)	(4,141)	(2,999)	9,914	(8,135)
Income (loss) before income taxes	(16,333)	(5,986)	(4,202)	10,052	(16,469)
Income tax (expense) benefit [1]	4,314	523	(387)	—	4,450

Net income (loss)	$(12,019)	$(5,463)	$(4,589)	$10,052	$(12,019)

[1] The income tax expense (benefit) reflected in each column does not include any tax effect of the equity in earnings (losses) of subsidiaries.

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

	Three months ended March 31, 2016			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$(15,583)	$ 24,998	$ 212	$ 9,627
Cash flows from investing activities:				
Purchases of property and equipment	(68)	(5,424)	(40)	(5,532)
Proceeds from sale of property and equipment	—	432	45	477
	(68)	(4,992)	5	(5,055)
Cash flows from financing activities:				
Debt issuance costs	(20)	—	—	(20)
Purchase of treasury stock	(43)	—	—	(43)
Intercompany contributions/distributions	14,275	(14,242)	(33)	—
	14,212	(14,242)	(33)	(63)
Net increase (decrease) in cash and cash equivalents	(1,439)	5,764	184	4,509
Beginning cash and cash equivalents	17,221	(5,612)	2,551	14,160
Ending cash and cash equivalents	$15,782	$ 152	$ 2,735	$ 18,669

	Three months ended March 31, 2015			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$(18,220)	$ 86,131	$ (3,030)	$ 64,881
Cash flows from investing activities:				
Purchases of property and equipment	(268)	(44,667)	(740)	(45,675)
Proceeds from sale of property and equipment	22	6,250	4	6,276
Proceeds from insurance recoveries	—	37	—	37
	(246)	(38,380)	(736)	(39,362)
Cash flows from financing activities:				
Debt repayments	(25,000)	(2)	—	(25,002)
Debt issuance costs	(5)	—	—	(5)
Proceeds from exercise of options	601	—	—	601
Purchase of treasury stock	(359)	—	—	(359)
Intercompany contributions/distributions	45,059	(45,022)	(37)	—
	20,296	(45,024)	(37)	(24,765)
Net increase (decrease) in cash and cash equivalents	1,830	2,727	(3,803)	754
Beginning cash and cash equivalents	27,688	(5,516)	12,752	34,924
Ending cash and cash equivalents	$29,518	$ (2,789)	$ 8,949	$ 35,678

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, 2015, 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. Other unpredictable or unknown factors 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) recognize 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. provides land-based drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies in 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 and enable us to meet multiple needs of our clients.

- Drilling Services Segment— From 1999 to 2011, we significantly expanded our fleet through acquisitions and the construction of new drilling rigs. As our industry changed with the evolution of shale drilling, we began a transformation process in 2011, by selectively disposing of our older, less capable rigs, while we continued to invest in our rig building program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients. We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us to compete well, grow our presence in the significant shale basins in the US, and improve profitability upon recovery of our industry.

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. The drilling rigs in our fleet are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	6
West Texas	7
North Dakota	6
Appalachia	4
Colombia	8
	31

- Production Services Segment— 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 further expand our production services offerings. Since the acquisitions of these businesses, we continued to invest in their organic growth and have significantly expanded all our production services fleets.

Our Production Services Segment provides a range of services to a diverse group of exploration and production companies, with our operations 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 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 March 31, 2016, we have a fleet of 114 rigs with 550 horsepower and 11 rigs with 600 horsepower with operations in 10 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota.
- Wireline Services. Oil and gas exploration and production companies require wireline services to better understand the reservoirs they are drilling or producing, and use logging services to accurately characterize reservoir rocks and fluids. To complete a cased-hole 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 in addition to a range of other mechanical services that

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are needed in order to place equipment in or retrieve equipment or debris from the wellbore, install bridge plugs and control pressure. As of March 31, 2016, we have a fleet of 125 wireline units in 17 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 March 31, 2016, 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. (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. Over the last 15 years, we have significantly expanded our business through acquisitions and organic growth. We conduct our operations through two operating segments: our Drilling Services Segment and our Production Services Segment. 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.

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

Industry Overview — 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 is primarily driven by current and expected oil and natural gas prices.

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.

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. However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced, and the demand for all our service offerings is significantly impacted.

Market Conditions — 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, and to a lesser extent, additional activity from other producers in the region.

Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for equipment in our industry. For the several years prior to late 2014, 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, overall demand remained steady, particularly for drilling rigs that are able to drill horizontally. During this same period, the demand for certain drilling rigs decreased, particularly in vertical well markets. The decline was a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling" which 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, then coupled with the current downturn, resulted in significantly reduced demand for drilling rigs that do not have the ability to walk or skid and to drill horizontal wells.

Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. At the end of 2015, the spot prices of WTI crude oil and Henry Hub natural gas were down by 66% and 74%, respectively, as compared to the peak 2014 prices. During this same period, the horizontal and vertical drilling rig counts in the United States dropped by 61% and 78%, respectively, while the domestic well servicing rig count decreased by 38%, as compared to the respective highest counts during 2014. Commodity prices have remained low during 2016 and continue to depress activity and pricing for all our service offerings.

In drilling, all rig classes have been severely impacted by the industry downturn. As a result, term contracts for 19 of our drilling rigs were terminated early, including three which were terminated in early 2016, and resulting in a total of $62.8 million of early termination payments. We recognized $49.2 million and $0.3 million of revenue for early termination payments during the years ended December 31, 2015 and 2014, respectively. We recognized $7.1 million during the first quarter of 2016 and we will recognize the remaining $6.2 million during the second and third quarters of 2016.

Currently, 13 of our 23 domestic drilling rigs are earning revenues, 10 of which are under term contracts, two of which have been terminated early. Of the eight rigs in Colombia, three are under term contracts, but have been put on standby by our client and are not earning revenue. We are actively marketing our idle drilling rigs in Colombia to various operators to diversify our client base, and evaluating other options, including the possibility of the sale of some or all of our assets in Colombia. Our well servicing and coiled tubing utilization rates for the quarter ended March 31, 2016 were 44% and 24%, respectively, based on total fleet count, and we are currently actively marketing approximately 55% of our wireline fleet.

If oil and natural gas prices remain at current levels for an extended period of time, or if oil prices decline further, then industry equipment utilization and revenue rates would likely decrease further. Our clients significantly reduced both their operating and capital expenditures during 2015, and we expect further reductions to their budgets for 2016. We expect continued pricing pressure, low activity levels and a highly competitive environment in 2016, but we believe our high-quality equipment and services are well positioned to compete.

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, 2015.

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 many of the most attractive drilling markets throughout the United States and in Colombia.

With the decline in oil prices and the reductions in our utilization and revenue rates over the last eighteen months, our near-term efforts are focused on:

- Cost Reductions. In 2015, we reduced our total headcount by 52%, reduced wage rates for our operations personnel, reduced incentive compensation and closed nine location offices to reduce overhead and reduce associated lease payments. In 2016, we further reduced our headcount, had additional wage rate reductions for certain operations personnel, and eliminated certain employment benefits. We will continue to evaluate opportunities to lower our cost structure in response to reduced revenues.
- Liquidating Nonstrategic Assets. We sold 32 drilling rigs and other drilling equipment during 2015 for aggregate net proceeds of $53.6 million, and placed four additional rigs as held for sale. We will continue to evaluate our domestic and international fleets for additional drilling rigs or equipment for which a near term sale would be favorable.
- Maintaining Liquidity and Financial Flexibility. We amended our revolving credit facility in September 2015 and again in December 2015, in order to maintain access to capital but with more flexible financial covenants, and we have availability for equity or debt offerings up to $300 million under our shelf registration statement. Additionally, we paid down $60 million of debt during 2015.
- Performance of our Core Businesses. We will continue to focus on maintaining our relationships with our clients and vendors through the downturn, and continue to focus on our service quality and safety. During this difficult time, we remain committed to our safety and service quality goals, and our 2015 total recordable incident rate is the lowest we have achieved since our company's inception.

We will continue to evaluate our business and look for opportunities to further achieve these goals, which we believe will position us to take advantage of future business opportunities and continue our long-term growth strategy.

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:

- Investments in the Growth of our Business. We have historically invested in the growth of our business by strategically upgrading our existing assets and disposing of assets which use older technology, and engaging in select rig building opportunities and acquisitions.

Since the beginning of 2010, we have added significant capacity to our production services offerings through the addition of 62 wireline units, 51 well servicing rigs and 17 coiled tubing units. We constructed ten AC drilling rigs from 2011 to 2013 and we completed construction of five new 1,500 horsepower AC drilling rigs during 2015. We sold 32 of our mechanical and lower horsepower electric drilling rigs during 2015, which were the most negatively impacted by the industry downturn, and placed an additional 4 rigs as held for sale.

We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us to compete well, grow our presence in the significant shale basins in the US, and improve profitability upon recovery of our industry.

- Competitive Position in the Prominent 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. The 15 drilling rigs which we constructed in the last five years are well suited for our operations in the Marcellus/Utica and Eagle Ford shales, the Permian Basin and the Bakken. Additionally, we have added significant capacity in recent years to our production services fleets, which we believe are well positioned to 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 markets offer the most opportunity.

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 $18.7 million as of March 31, 2016), 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 March 31, 2016, 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 December 23, 2015, 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 $200 million, subject to availability under a borrowing base comprised of certain eligible cash, certain eligible receivables, certain eligible inventory, and certain eligible equipment of ours and certain of our subsidiaries, all of which matures in March 2019. As of March 31, 2016, we had $95 million outstanding under our Revolving Credit Facility and $17.3 million in committed letters of credit, which resulted in borrowing availability of $87.7 million under our Revolving Credit Facility. Borrowings under the Revolving Credit Facility are available for selective acquisitions, working capital and other general corporate purposes. There are no limitations on our ability to access the 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.

At March 31, 2016, we were in compliance with our financial covenants under the Revolving Credit Facility. However, continued compliance with our covenants is largely dependent on our ability to generate sufficient levels of EBITDA, as defined in the Revolving Credit Facility, and/or reduce our debt levels. If we expect our future operating results to decline to a level that indicates we may become unable to comply with the financial covenants in the Revolving Credit Facility, we may seek to amend such provisions to remain in compliance or we may pursue other capital sources, such as other debt or equity transactions. Although we believe that our bank lenders are well-secured under the terms of our Revolving Credit Facility, there is no assurance that the bank lenders will waive or amend our financial covenants under the Revolving Credit Facility.

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 three months ended March 31, 2016, we spent $5.5 million on purchases of property and equipment and placed into service property and equipment of $5.5 million. Currently, we expect to spend approximately $25 million on capital expenditures during 2016. We expect the total capital expenditures for 2016 will be allocated approximately 60% for our Drilling Services Segment and approximately 40% for our Production Services Segment. Our total planned capital expenditures for 2016 are limited to primarily routine capital expenditures, the remaining payments for the new drilling rigs which we deployed in late 2015 and certain drilling equipment that was ordered in 2014 but requires a long lead time for delivery.

Actual capital expenditures may vary depending on the climate of our industry and any resulting increase or decrease in activity levels, the timing of commitments and payments, and the level of rig build and other expansion opportunities that meet our strategic and return on capital employed criteria. We expect to fund the remaining capital expenditures in 2016 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 $41.1 million at March 31, 2016, compared to $45.2 million at December 31, 2015. Our current ratio, which we calculate by dividing current assets by current liabilities, was 1.7 at March 31, 2016, compared to 1.6 at December 31, 2015.

Our operations have historically generated cash flows sufficient to meet our requirements for debt service and normal capital expenditures. However, our working capital requirements generally increase during periods when rig construction projects are in progress or when higher percentages of our drilling contracts are turnkey contracts, at which times we are more likely to access capital through debt or equity financing.

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

	March 31, 2016	December 31, 2015	Change
Cash and cash equivalents	$ 18,669	$ 14,160	$4,509
Receivables:			
Trade, net of allowance for doubtful accounts	42,227	47,577	(5,350)
Unbilled receivables	4,144	13,624	(9,480)
Insurance recoveries	15,196	14,556	640
Other receivables	3,856	4,059	(203)
Inventory	8,501	9,262	(761)
Assets held for sale	4,276	4,619	(343)
Prepaid expenses and other current assets	6,678	7,411	(733)
Current assets	103,547	115,268	(11,721)
Accounts payable	12,966	16,951	(3,985)
Deferred revenues	7,878	6,222	1,656
Accrued expenses:			
Payroll and related employee costs	14,346	13,859	487
Insurance premiums and deductibles	6,676	8,087	(1,411)
Insurance claims and settlements	15,196	14,556	640
Interest	919	5,508	(4,589)
Other	4,459	4,859	(400)
Current liabilities	62,440	70,042	(7,602)
Working capital	$ 41,107	$ 45,226	$(4,119)

The increase in cash and cash equivalents during the three months ended March 31, 2016 is primarily due to $9.6 million of cash provided by operating activities, which includes early termination payments made on certain drilling contracts, and $0.5 million of proceeds from the sale of assets, partially offset by $5.5 million of cash used for purchases of property and equipment.

The net decrease in our total trade and unbilled receivables as of March 31, 2016 as compared to December 31, 2015 is primarily the result of the decrease in consolidated revenues of $29.5 million, or 28%, for the quarter ended March 31, 2016 as compared to the quarter ended December 31, 2015.

The increase in both our insurance recoveries receivables and our insurance claims and settlements accrued expenses as of March 31, 2016 as compared to December 31, 2015 is primarily due to an increase in our insurance company's reserve for workers' compensation claims in excess of our deductibles.

The decrease in other receivables as of March 31, 2016 as compared to December 31, 2015 is primarily due to a the receipt of a property tax refund in the first quarter and a decrease in receivables for vendor purchase rebates due to a decline in activity. The decrease in other receivables was partially offset by an increase in net income tax receivables for our Colombian operations.

The decrease in inventory as of March 31, 2016 as compared to December 31, 2015 is primarily due to a decline in activity for our wireline and coiled tubing operations.

As of March 31, 2016, our condensed consolidated balance sheet reflects assets held for sale of $4.3 million, which primarily represents the fair value of four drilling rigs and other equipment.

The decrease in prepaid expenses and other assets as of March 31, 2016 as compared to December 31, 2015 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 five months of these October premiums at March 31, 2016, as compared to two months at December 31, 2015.

The decrease in accounts payable as of March 31, 2016 as compared to December 31, 2015 is primarily due to the 25% decrease in our operating costs for the quarter ended March 31, 2016 as compared to the quarter ended December 31, 2015.

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The increase in deferred revenues as of March 31, 2016 as compared to December 31, 2015 is primarily related to deferred revenue for early termination payments. Revenues derived from rigs placed on standby or from the early termination of 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. (See Critical Accounting Policies and Estimates section for more detail.)

The increase in accrued payroll and employee related costs as of March 31, 2016 as compared to December 31, 2015 is primarily due to the timing of pay periods and associated withholding and unemployment tax payments, mostly offset by a decrease in annual incentive compensation associated with the payment of 2015 annual bonuses which were fully accrued at December 31, 2015 and were paid in the first quarter of 2016.

The decrease in insurance premiums and deductibles as of March 31, 2016 as compared to December 31, 2015 is primarily due to a decrease in our health insurance costs resulting from a decrease in our estimated liability for the deductibles under these policies, partly as a result of reduced headcount.

The decrease in accrued interest expense is primarily due to the payment of interest on our Senior Notes which is due semi-annually on March 15 and September 15.

The decrease in other accrued expenses as of March 31, 2016 as compared to December 31, 2015 is primarily due to a decrease in our property tax accruals due to timing of payments, partially offset by an accrual of $0.8 million for the 2016 Colombian wealth tax which is assessed annually in the first quarter.

Long-term Debt and Other Contractual Obligations

The following table includes information about the amount and timing of our contractual obligations at March 31, 2016 (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	$395,000	$—	$95,000	$—	$300,000
Interest on debt	127,398	23,306	46,611	39,106	18,375
Purchase commitments	9,707	9,707	—	—	—
Operating leases	11,464	3,292	5,007	2,807	358
Incentive compensation	17,347	4,736	9,761	2,850	—
Total	$560,916	$41,041	$156,379	$44,763	$318,733

Debt obligations at March 31, 2016 consist of $300 million of principal amount outstanding under our Senior Notes which mature on March 15, 2022 and $95 million outstanding under our Revolving Credit Facility which is due at maturity on March 31, 2019. However, we may make principal payments to reduce the outstanding balance under our Revolving Credit Facility prior to maturity when cash and working capital is sufficient.

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 5.2% interest rate that was in effect at March 31, 2016, and (2) the outstanding balance of $95 million at March 31, 2016 to be paid at maturity on March 31, 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 purchases of new equipment and equipment upgrades, including $7.1 million for new drilling equipment that was ordered during 2014, but which requires a long lead-time for delivery.

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. A portion of our incentive compensation is performance-based and therefore the final amount will be determined based on our actual performance relative to a pre-determined peer group over the performance period.

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 cash-collateralize letter of credit exposure. There are no limitations on our ability to access the 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 March 31, 2016, we were in compliance with our financial covenants under the Revolving Credit Facility. Our senior consolidated leverage ratio was 1.3 to 1.0 and our interest coverage ratio was 3.9 to 1.0. However, continued compliance with our covenants is largely dependent on our ability to generate sufficient levels of EBITDA, as defined in the Revolving Credit Facility, and/or reduce our debt levels. If we expect our future operating results to decline to a level that indicates we may become unable to comply with the financial covenants in the Revolving Credit Facility, we may seek to amend such provisions to remain in compliance or we may pursue other capital sources, such as other debt or equity transactions. Although we believe that our bank lenders are well-secured under the terms of our Revolving Credit Facility, there is no assurance that the bank lenders will waive or amend our financial covenants under the Revolving Credit Facility.

The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum senior consolidated leverage ratio, calculated as senior consolidated debt at the period end, which excludes unsecured and subordinated debt, divided by EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility. The senior consolidated leverage ratio cannot exceed the following maximum amounts as follows:

3.00	to 1.00	on March 31, 2016
3.50	to 1.00	on June 30, 2016
4.25	to 1.00	on September 30, 2016
4.75	to 1.00	on December 31, 2016
4.75	to 1.00	on March 31, 2017
4.75	to 1.00	on June 30, 2017
4.25	to 1.00	on September 30, 2017
3.50	to 1.00	on December 31, 2017
3.50	to 1.00	on March 31, 2018
3.25	to 1.00	on June 30, 2018
2.50	to 1.00	at any time after June 30, 2018

- A minimum interest coverage ratio, calculated as EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility, divided by interest expense for the same period. The interest coverage ratio cannot be less than the following minimum amounts as follows:

1.50	to 1.00	for each quarterly period ending March 31, 2016 through June 30, 2016
1.25	to 1.00	for each quarterly period ending September 30, 2016 through September 30, 2017
1.50	to 1.00	at any time after September 30, 2017

The Revolving Credit Facility also does not restrict capital expenditures as long as (a) no event of default under the Revolving Credit Facility exists or would result from such expenditures, and (b) such expenditures do not cause total capital expenditures to exceed $50 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 $25 million.

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, repurchases of capital stock, 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 March 31, 2016, 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 months ended March 31, 2016 and 2015 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Three months ended March 31,	
	2016	2015
Drilling Services Segment:		
Revenues	$33,184	$98,415
Operating costs	17,440	62,295
Drilling Services Segment margin	$15,744	$36,120
Average number of drilling rigs	31.0	46.2
Utilization rate	46 %	83 %
Revenue days	1,310	3,457
Average revenues per day	$25,331	$28,468
Average operating costs per day	13,313	18,020
Drilling Services Segment margin per day	$12,018	$10,448
Production Services Segment:		
Revenues	$41,768	$95,399
Operating costs	34,849	68,769
Production Services Segment margin	$6,919	$26,630
Combined:		
Revenues	$74,952	$193,814
Operating costs	52,289	131,064
Combined margin	$22,663	$62,750
Adjusted EBITDA	$6,421	$36,758

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, any loss on extinguishment of debt and any 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.

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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 March 31,	
	2016	2015
	(amounts in thousands)	
Reconciliation of combined margin and Adjusted EBITDA to net income (loss):		
Combined margin	$22,663	$62,750
General and administrative	(16,508)	(21,860)
Bad debt (expense) recovery	55	(319)
Gain (loss) on dispositions of property and equipment, net	600	(1,133)
Other expense	(389)	(2,680)
Adjusted EBITDA	6,421	36,758
Depreciation and amortization	(29,824)	(41,782)
Impairment charges	—	(5,990)
Interest expense	(6,254)	(5,455)
Income tax benefit	1,958	4,450
Net loss	$(27,699)	$(12,019)

Both our Drilling Services and Production Services Segments experienced a significant decline in activity during the three months ended March 31, 2016, as compared to the corresponding period in 2015, due to the current downturn in our industry. Our combined margin decreased for the three months ended March 31, 2016 as compared to the corresponding period in 2015, primarily as a result of decreased activity and pricing pressure for all our service offerings. The decrease in combined margin was partially offset by an increase in average margin per day in our Drilling Services Segment from newly built rigs that were deployed during 2015, rigs that were earning but not working and the disposal of mechanical and lower horsepower electric drilling rigs from our fleet during 2015 which generally earned lower margins per day.

Our Drilling Services Segment’s revenues decreased by $65.2 million, or 66%, and our Drilling Services Segment’s operating costs decreased by $44.9 million, or 72%, for the three months ended March 31, 2016 as compared to the corresponding period in 2015, primarily resulting from a decrease in revenue days, both for our domestic and international operations, and lower average operating costs per day. Revenue days decreased primarily due to the significant reduction in demand in our industry. Our average operating costs per day decreased by $4,707 per day, or 26%, while our average revenues per day decreased by $3,137 per day, or 11%, for the three months ended March 31, 2016 as compared to the corresponding period in 2015. Our average operating costs and revenues per day decreased primarily due to drilling rigs which were early terminated and were thus earning lower standby revenue rates while also incurring minimal operating costs, as well as reduced activity for our Colombian operations, for which we typically earn higher dayrates and incur higher operating costs per day. During the three months ended March 31, 2016 and 2015, we recognized $7.1 million and $11.3 million, respectively, of revenues associated with drilling contracts that were terminated early, representing 296 and 449 of associated revenue days, respectively. The decrease in average revenues per day was partially offset by the contribution from new drilling rigs deployed during 2015 which operate in higher demand regions and typically earn higher dayrates.

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. During the three months ended March 31, 2016 and 2015, we completed 1 and 14 turnkey contracts, which represented 2% and 6% of our total drilling revenues, respectively.

Our Production Services Segment's revenues decreased by $53.6 million, or 56%, for the three months ended March 31, 2016 as compared to the corresponding period in 2015, while operating costs decreased by $33.9 million, or 49%. 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 led to decreased activity and increased pricing pressure for all our service offerings, especially our wireline services and coiled tubing operations. The number of wireline jobs we completed decreased by 38% for the three months ended March 31, 2016, as compared to the corresponding period in 2015. The total rig hours for our well servicing fleet decreased by 40% for the three months ended March 31, 2016, as compared to the corresponding period in 2015. Our coiled tubing utilization decreased to 24% for the three months ended March 31, 2016 from 33% during the corresponding period in 2015.

In response to the downturn in our industry, we took several actions to reduce costs and better scale our business to the reduced revenues in 2015 and early 2016. We reduced our total headcount by 52% during 2015, reduced wage rates for our operations personnel, reduced incentive compensation and eliminated certain employment benefits. We closed nine location offices in 2015 to reduce overhead and reduce associated lease payments, amended our revolving credit facility, and sold 32 drilling rigs and other drilling equipment for aggregate net proceeds of $53.6 million.

Our general and administrative expense decreased by $5.4 million, or 24%, for the three months ended March 31, 2016 as compared to the corresponding period in 2015, primarily due to a $3.2 million decrease in compensation costs resulting from the reduction in our workforce, and other efforts taken during 2015 to minimize various administrative costs such as employee benefits, office and rent expenses and travel.

Our gains of $0.6 million on the disposition of property and equipment during the three months ended March 31, 2016 was primarily related to the disposal of excess drill pipe. Our losses of $1.1 million on the disposition of property and equipment during the three months ended March 31, 2015 was primarily for the sale of 20 of our mechanical and lower horsepower electric drilling rigs and other drilling equipment which we sold in March 2015.

The decrease in our other expense is primarily related to net foreign currency gains recognized for our Colombian operations during the three months ended March 31, 2016, as compared to net foreign currency losses during the corresponding period in 2015.

Our depreciation and amortization expense decreased by $12.0 million for the three months ended March 31, 2016, as compared to the corresponding period in 2015, primarily as a result of the sales of drilling rigs and equipment during 2015, as well as impairment charges during 2015 to reduce the carrying values of certain drilling rigs, coiled tubing equipment and intangible assets to their estimated fair values, and partially offset by approximately $2.5 million of depreciation for the five new drilling rigs which we deployed in 2015.

During the three months ended March 31, 2015, we recorded impairment charges of $6.0 million to reduce the carrying value of certain assets which were classified as held for sale, to their estimated fair values, based on expected sales prices.

Our interest expense increased by $0.8 million for the three months ended March 31, 2016 as compared to the corresponding period in 2015, due to the increased interest rate under our Revolving Credit Facility which was amended in September and December 2015.

Our effective income tax rate for the three months ended March 31, 2016 was 7%, which is lower than the federal statutory rate in the United States, primarily due to valuation allowances, the effect of foreign currency translation, state taxes, and other permanent differences.

Inflation

Wage rates for our operations personnel are impacted by inflationary pressures when the demand for drilling and production services increases and the availability of personnel is scarce. Costs for equipment repairs and maintenance, upgrades and new equipment construction are also impacted by inflationary pressures when the demand for drilling services increases. As a result of the significantly reduced activity levels in our industry during 2015, we estimate that we experienced a moderate decrease in both wage rate and equipment costs during 2015 for both our Drilling and Production Services Segments, and we expect modest decreases in 2016 as well.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions that affect the amounts reported in our financial statements and accompanying notes. Actual results could differ from those estimates. As of March 31, 2016, there were no significant changes to our critical accounting policies since the date of our annual report on Form 10-K for the year ended December 31, 2015.

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 proportional performance basis, 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 proportional performance basis 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 operations personnel.

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 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 often 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

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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 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 determine the fair value of the asset group. The amount of an impairment charge is measured as the difference between the carrying amount and the fair value of the 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 the valuation allowance for deferred tax assets, 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. If we anticipate a loss on a contract in progress 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 while completing services on contracts still in progress at the end of a reporting period. During the three months ended March 31, 2016, we did not experience a loss on any of the turnkey contracts completed. We incurred a total loss of $0.5 million on 3 of the 14 turnkey contracts completed during the three months ended March 31, 2015. As of March 31, 2016, we had no turnkey contracts in progress.

We estimate an allowance for doubtful accounts based on the creditworthiness of our clients as well as general economic conditions. We evaluate the creditworthiness of our clients based on commercial credit reports, trade references, bank references, financial information, production information and any past experience we have with the client. Consequently, any change in those factors could affect our estimate of our allowance for doubtful accounts. In some instances, we require new clients to establish escrow accounts or make prepayments. We had an allowance for doubtful accounts of $1.8 million at March 31, 2016.

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 in accordance with ASC Topic 360, Property, Plant and Equipment. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment.

As of March 31, 2016, we had $99.3 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 consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. As of March 31, 2016, we determined that a valuation allowance should be recorded for a portion of our domestic deferred tax assets, which has been factored into the estimated annual tax rate to be applied throughout 2016, and is the primary factor causing our effective tax rate to be significantly lower than the statutory rate of 35%. We also have a valuation allowance that fully offsets our $17.3 million of foreign deferred tax assets. For more information, see Note 3, Valuation Allowances on Deferred Tax Assets, of the Notes to Condensed Consolidated Financial Statements, included in Part I, Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Our accrued insurance premiums and deductibles as of March 31, 2016 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $1.4 million and our workers' compensation, general liability and auto liability insurance of approximately $5.3 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 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 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.

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Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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 2018. 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 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, and that amortization of debt issuance costs be reported as interest expense. In August 2015, these provisions were further amended with guidance from the Securities and Exchange Commission Staff that they would not object to an entity deferring and presenting debt issuance costs related to line-of-credit arrangements as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and is effective for us beginning with our first quarterly filing in 2016. The adoption of this new standard resulted in reclassifying $7.8 million of debt issuance costs from other long-term assets to long-term debt in the accompanying December 31, 2015 condensed consolidated balance sheet.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases, which among other things, requires lessees to recognize substantially all leases on the balance sheet, with expense recognition that is similar to the current lease standard, and aligns the principles of lessor accounting with the principles of the FASB's new revenue guidance (referenced above). This ASU is effective for us beginning with our first quarterly filing in 2019. We are currently evaluating the potential impact of this guidance and have not yet determined its impact on our financial position and results of operations.

Stock-Based Compensation. In March 2016, the FASB issued ASU No. 2016-09, Stock Compensation: Improvements to Employee Share-Based Payment Accounting, to reduce complexity in accounting standards involving several aspects of the accounting for employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This ASU is effective for us beginning with our first quarterly filing in 2017. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this update will have a material effect 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 March 31, 2016, we had $95.0 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 $0.2 million, and a corresponding increase or decrease, respectively, in net income of approximately $0.2 million during the three months ended March 31, 2016. 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, 2016.

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

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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 gains of $0.2 million for the three months ended March 31, 2016.

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 March 31, 2016, 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.

In the ordinary course of business, we may make changes to our systems and processes to improve controls and increase efficiency, and make changes to our internal controls over financial reporting in order to ensure that we maintain an effective internal control environment. There have been no changes in our internal control over financial reporting during the three months ended March 31, 2016 that have materially affected, or are 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 March 31, 2016. The following table provides information relating to our repurchase of common shares during the quarter ended March 31, 2016:

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
January 1 - January 31	31,366	$ 1.36	—	—
February 1 - February 29	—	$ —	—	—
March 1 - March 31	218	$ 2.10	—	—
Total	31,584	$ 1.37	—	—

(1) The shares indicated consist of shares of our common stock tendered by employees to the Company during the three months ended March 31, 2016, 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+**	-	Employment Letter, effective May 1, 2012, from Pioneer Drilling company to Brian L. Tucker.
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 March 31, 2016, 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: April 29, 2016

Index to Exhibits

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