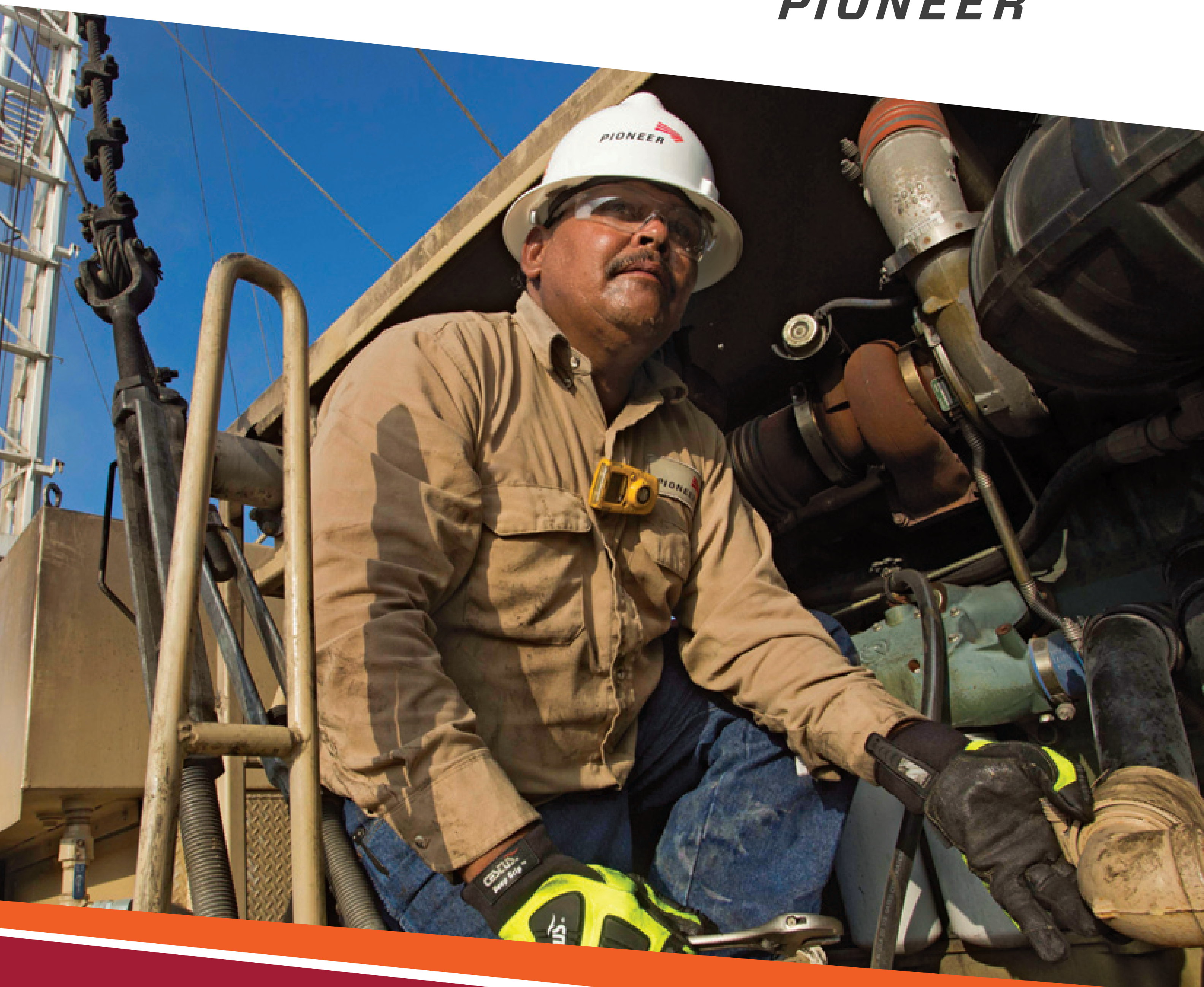
Pioneer Energy Services

2014 ANNUAL REPORT

PIONEER



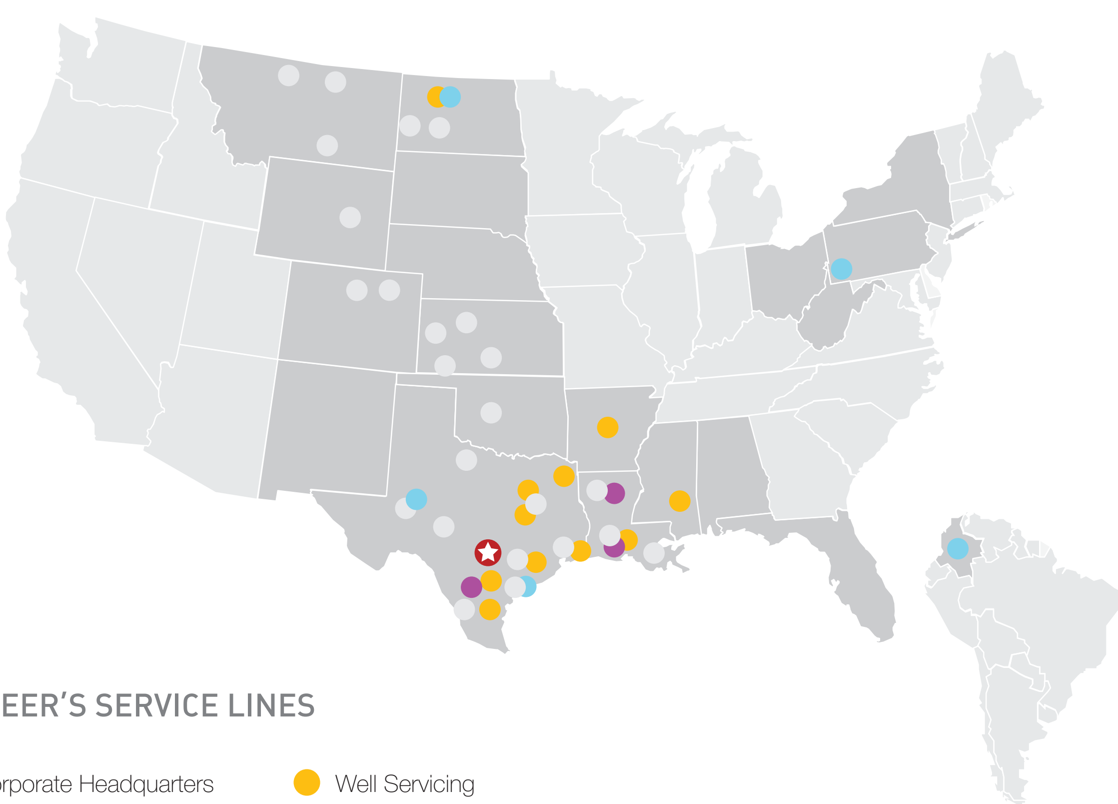
EVERY PROJECT
IS PERSONAL

SELECTED FINANCIAL DATA

(In thousands, except per share data)	2014 (3)	2013 (2)	2012	2011	2010
Revenues	$1,055,223	$960,186	$919,443	$715,941	$487,210
Net income (loss)	(38,018)	(35,932)	30,032	11,177	(33,261)
Adjusted EBITDA(1)	277,081	234,742	249,283	183,870	103,151
Income (loss) per common share - diluted	(0.60)	(0.58)	0.48	0.19	(0.62)
Total assets	1,171,589	1,229,623	1,339,776	1,172,754	841,343
Long-term debt and capital lease obligations, excluding current installments	455,053	499,666	518,725	418,728	279,530
Shareholders' equity	495,064	518,433	547,680	510,445	396,333
Net cash provided by operating activities	233,041	174,580	199,366	144,879	98,351

(1) For a reconciliation of the difference between this financial measure, which is not in accordance with U.S. Generally Accepted Accounting Principles (GAAP), and the most directly comparable financial measure, which calculated in accordance with GAAP, see the last page of this Annual Report following the Form 10-K.
(2) Includes goodwill and intangible asset impairment charges of $44.8 million ($27.1 million net of tax).
(3) Includes property and equipment impairment charges of $73.0 million ($45.3 million net of tax).

AREAS OF OPERATIONS



PIONEER'S SERVICE LINES

- Corporate Headquarters
- Wireline Services
- Drilling Services
- Well Servicing
- Coiled Tubing Services

Wm. Stacy Locke
President and Chief Executive Officer

To Our Shareholders and Employees,

2014 was a banner year for Pioneer. We broke the $1 billion mark in revenues for the first time in our Company's history, and each of our four core businesses contributed meaningfully in terms of revenue growth, profitability, service excellence and best-in-class safety performance.

While we enjoyed strong demand for our services during 2014, storm clouds began brewing late in the year. The price of oil, which was over $100 per barrel in the middle of 2014, fell below $90 per barrel in October and continued to decline sharply through the remainder of the year, reaching $44 per barrel in January 2015. Oil and gas operators were quick to respond by releasing drilling rigs and negotiating price reductions for all our services.

By late March 2015, over 800 drilling rigs in the U.S., or 45% of the total, had been released. Rigs drilling vertical and directional wells were hit first and the hardest, but rigs drilling horizontal wells in the shale and unconventional plays were also materially impacted. With oil prices remaining soft, more drilling rigs are being released as we head into the second quarter of 2015.

We have also been quick to respond to these rapidly changing market conditions by reducing operating expense, capital outlays and continuing to de-lever our balance sheet. As Pioneer faces this difficult environment, we believe our balance sheet is healthy and we have a more resilient revenue base through our diversified services. During 2014, we refinanced our long-term debt, increased our revolving line of credit, and paid down more than $50 million in outstanding debt. The end result was an approximate $23 million per year reduction of interest expense, which is about a 50% decrease, and improved financial flexibility.

DRILLING SERVICES SEGMENT

Our drilling services business performed well in 2014 with strong demand during the first three quarters of the year; however, the industry is evolving away from vertical wells to horizontal wells and the steep decline in commodity prices is intensifying this shift. The first rigs to stack when oil prices fell were the mechanical rigs drilling vertical wells. Our client base is clearly emphasizing horizontal wells over vertical wells based on a better return on investment. As a result, we have moved quickly to adapt to this shift in demand and in the first quarter of 2015 have sold almost all of our mechanical rigs and other lower horsepower electric rigs. The cash proceeds generated from these rig sales will help fund our five new-build, latest generation AC-powered rigs. These new drilling rigs are contracted for multi-year terms at very attractive pricing and will be drilling horizontal wells in the Eagle Ford, Permian and Bakken resource plays with quality clients. Our strategic focus going forward will be to design and build the most advanced and competitive drilling rigs for the horizontal markets.

Our eight-rig operation in Colombia is experiencing similar pressures as the U.S. market. Utilization and pricing are depressed and will likely remain that way for the remainder of the year. We have been the top-performing contractor in Colombia for many years and remain hopeful that we will continue to have opportunities in the country for years to come.

PRODUCTION SERVICES SEGMENT

Well Servicing

Our well servicing business achieved record sales and operating margins in 2014, and we believe it is one of the best performing in the industry. We increased our unit count by seven rigs during 2014 and ended the year at 116 rigs. We plan to add nine more units in 2015. Well Servicing appears to be holding up better than our other businesses during the weak oil price environment; however, both pricing and utilization for this business will be negatively impacted to a degree in 2015.

Wireline Services

Wireline Services performed very well in 2014, achieving its highest revenue ever and with impressive operating margins. Our wireline fleet increased by one unit to 120 during 2014, and we took delivery of an additional eight units in first quarter of 2015. Pricing and activity levels came under pressure as the oil prices declined and we anticipate 2015 will be a challenging year for wireline services.

Coiled Tubing Services

Our coiled tubing business delivered a remarkable improvement in 2014. We focused our operations on key markets and were able to deliver consistent, high-quality and safe services. We grew our coiled tubing fleet by four units to 17 and increased our breadth of service offerings. Like wireline, coiled tubing will face pricing and utilization headwinds in 2015.

OUTLOOK

There is no question that 2015 will be a challenging year. However, our industry-leading safety record and solid reputation for quality has enabled us to attract and retain the best clients in the industry through up and down cycles. Our goal is to remain cash neutral during the current down cycle by scaling back our cost structure and keeping a tight rein on capital expenditures. Revenues will come down but so will costs.

Historically, down cycles last 12 to 18 months and, at the present time, we don't see this cycle being any different. Rig count has come down rapidly, and this should cause U.S. production growth to slow and, perhaps, be flat month-over-month by year-end. As U.S. production growth slows, oil pricing should begin to gradually improve, ultimately leading to increased activity levels and later to improved pricing for our equipment and services.

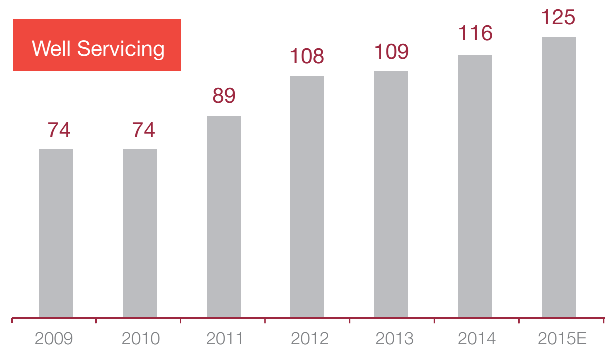
We are well positioned to weather the downturn and emerge leaner, stronger and more competitive than before with a top-quality equipment fleet, a blue chip client base, and the financial flexibility to act quickly on opportunities that present themselves in the next market upswing. I want to thank our dedicated employees for their contributions in 2014 and our shareholders for their long-standing support.

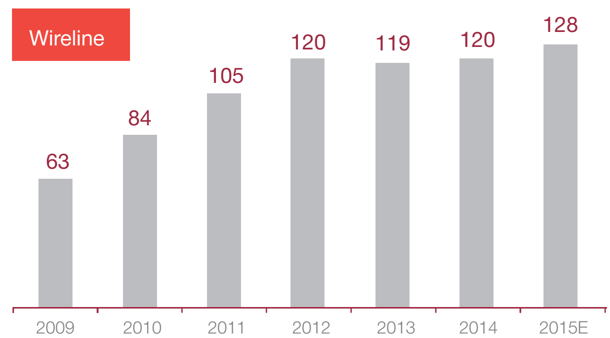
Sincerely,

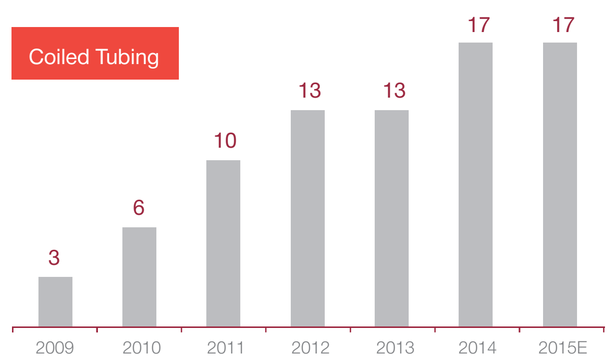
Wm. Stacy Locke

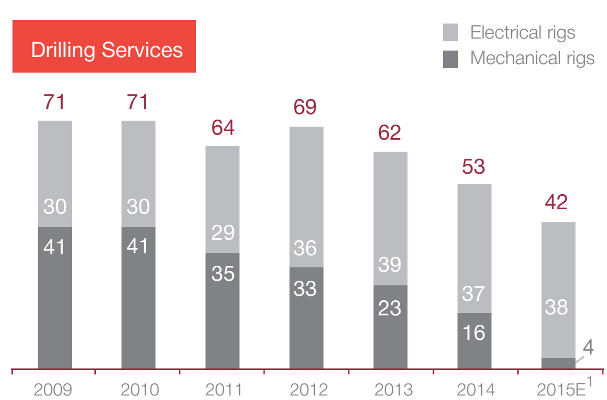
Wm. Stacy Locke
PRESIDENT AND CHIEF EXECUTIVE OFFICER

FLEET COMPOSITION









(1) At March 31, 2015, we had a marketable fleet of 37 drilling rigs.

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

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2014
or

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

Commission File Number: 1-8182

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

TEXAS	**74-2088619**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
1250 N.E. 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
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.10 par value	**NYSE**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 ☑ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, 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 ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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. (Check one):

Large accelerated filer ☑		Accelerated filer ☐
Non-accelerated filer ☐	(Do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of the registrant's common stock held by nonaffiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter (based on the closing sales price on the New York Stock Exchange (NYSE) on June 30, 2014) was approximately $1.1 billion.

As of January 29, 2015, there were 63,867,955 shares of common stock, par value $0.10 per share, of the registrant issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2015 Annual Meeting of Shareholders are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

PART I

INTRODUCTORY NOTE

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

From time to time, our management or persons acting on our behalf make forward-looking statements to inform existing and potential security holders about our company. These statements may include projections and estimates concerning the timing and success of specific projects and our future backlog, revenues, income and capital spending. Forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “plan,” “intend,” “seek,” “will,” “should,” “goal” or other words that convey the uncertainty of future events or outcomes. These forward-looking statements speak only as of the date on which they are first made, which in the case of forward-looking statements made in this report is the date of this report. Sometimes we will specifically describe a statement as being a forward-looking statement and refer to this cautionary statement.

In addition, various statements contained in this Annual Report on Form 10-K, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements. Such forward-looking statements appear in Item 1—“Business” and Item 3—“Legal Proceedings” in Part I of this report; in Item 5—“Market for Registrant’s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities,” Item 7—“Management’s Discussion and Analysis of Financial Condition and Results of Operations,” Item 7A—“Quantitative and Qualitative Disclosures About Market Risk” and in the Notes to Consolidated Financial Statements we have included in Item 8 of Part II of this report; and elsewhere in this report. These forward-looking statements speak only as of the date of this report. We disclaim any obligation to update these statements, and we caution you not to place undue reliance on them. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- 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 believe the items we have outlined above are important factors that could cause our actual results to differ materially from those expressed in a forward-looking statement contained in this report or elsewhere. We have discussed many of these factors in more detail elsewhere in this report. 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. We undertake no duty to update or revise any forward-looking statements, except as required by applicable securities laws and regulations. We advise our security holders that they should (1) be aware that unpredictable or unknown 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. Also, please read the risk factors set forth in Item 1A—"Risk Factors."

Item 1. Business

General

Pioneer Energy Services Corp. (formerly called "Pioneer Drilling Company") was incorporated under the laws of the State of Texas in 1979 as the successor to a business that had been operating since 1968. Since September 1999, we have significantly expanded our drilling rig fleet through acquisitions and through the construction of rigs from new and used components. In March 2008, we acquired two production services companies which significantly expanded our service offerings to include well servicing and wireline services. Through these purchases, we also acquired fishing and rental services operations, which were subsequently sold on September 17, 2014. We also acquired a coiled tubing services business at the end of 2011, to expand our existing production services offerings. We have continued to invest in the growth of all our core service offerings through acquisitions and organic growth.

Pioneer Energy Services Corp. provides drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies throughout much of the onshore oil and gas producing regions of the United States and internationally in Colombia. We also provide coiled tubing and wireline services offshore in the Gulf of Mexico. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of a well site and enable us to meet multiple needs of our clients.

We currently conduct our operations through two operating segments: our Drilling Services Segment and our Production Services Segment. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 11, *Segment Information*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

- *Drilling Services Segment*—Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies through our six drilling divisions in the US and internationally in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on either a daywork or turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed.

  Since October 2014, domestic and international oil prices have declined significantly to historically low price levels resulting in a downturn in our industry. As a result, we performed an impairment evaluation of all our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*, which resulted in $71.0 million of impairment charges to reduce the carrying value of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value.

  Mechanical and lower horsepower drilling rigs are the most impacted by the industry downturn and are typically the first rigs to become idle. As of December 31, 2014, we owned a total of 31 mechanical and lower horsepower electric drilling rigs, which includes the nine rigs that were idle and classified as held for sale as of year-end and 15 rigs that we expect to place as held for sale during the first quarter of 2015, after their current contracts are completed. In January and February 2015, we sold six of these drilling rigs.

The following is a summary of our drilling rig counts as of December 31, 2014 and February 1, 2015, as well as our expected count at March 31, 2015.

	Drilling Rigs Owned	Drilling Rigs Held for Sale	Drilling Rig Fleet Count
As of December 31, 2014	62	(9)	53
As of February 1, 2015	59	(12)	47
Expected at March 31, 2015	56	(18)	38

As of February 1, 2015, the drilling rigs in our fleet are assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
West Texas	10
North Dakota	9
Utah	4
Appalachia	3
Colombia	8
	47

We are currently constructing five new-build 1,500 horsepower AC drilling rigs which we expect to deliver and begin operating under long-term drilling contracts in 2015, with the first two rigs to be deployed during the second quarter, two rigs in the third quarter, and the final rig by the end of the year. Excluding the rigs which we expect to sell in the near-term and considering the five new-build drilling rigs under construction, we expect to end 2015 with a drilling fleet of 43 rigs.

As of February 1, 2015, 40 of our 47 drilling rigs are earning revenues under drilling contracts, 29 of which are earning under term contracts. Four of our drilling rigs in Colombia are currently working under term contracts that extend through mid-2015 and we are actively marketing our other four rigs to multiple clients to diversify our client base in Colombia.

In response to the dramatic decline in oil prices during recent months, we have received early termination notices for 12 of our 29 drilling rigs that are earning revenues under term contracts. These 12 drilling rigs will be released upon completion of their current wells, all of which are expected to be completed by the end of the first quarter 2015, resulting in approximately $43.5 million of early termination payments which will be recognized as revenue over the remaining term of the contracts, $0.3 million of which was recognized in 2014.

- *Production Services Segment*—Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. On September 17, 2014, we completed the sale of our fishing and rental services operations. We provide our services to a diverse group of oil and gas exploration and production companies. The primary production services we offer are the following:

  - Well Servicing. A range of services are required in order to establish production in newly-drilled wells and to maintain production over the useful lives of active wells. We use our well servicing rig fleet to provide these necessary services, including the completion of newly-drilled wells, maintenance and workover of active wells, and plugging and abandonment of wells at the end of their useful lives. As of February 1, 2015, we operate 107 rigs with 550 horsepower and 10 rigs with 600 horsepower through 11 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota.

  - Wireline Services. In order for oil and gas exploration and production companies to better understand the reservoirs they are drilling or producing, they require logging services to accurately characterize reservoir rocks and fluids. To complete a well, the production casing must be perforated to establish a flow path between the reservoir and the wellbore. We use our fleet of wireline units to provide these important logging and perforating services. We provide both open and cased-hole logging services, including the latest pulsed-neutron technology. In addition, we provide services which allow oil and gas exploration and production companies to evaluate the integrity of wellbore casing, recover pipe, or install bridge plugs. As of December 31, 2014, we have four wireline units placed as held for sale, for which we recognized approximately $0.3 million of impairment charges to reduce their carrying values to fair value. As of February 1, 2015, we operate a fleet of 128 wireline units through 24 locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

- Coiled Tubing. 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 February 1, 2015, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are currently deployed through three locations in Texas and Louisiana.

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

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 in turn is affected by current and expected oil and natural gas prices.

In recent years, generally increasing oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. Even though advancements in technology have improved the efficiency of drilling rigs, demand remained steady, particularly for drilling rigs that are able to drill horizontally. Beginning in October 2014, domestic and international oil prices have significantly declined to historically low price levels. If oil prices continue to decline, or if oil and natural gas prices remain at current levels for an extended period of time, then industry equipment utilization and revenue rates will further decrease, both domestically and in Colombia.

While drilling and production services have historically trended similarly in response to fluctuations in commodity prices, 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 expenditures to sustain production.

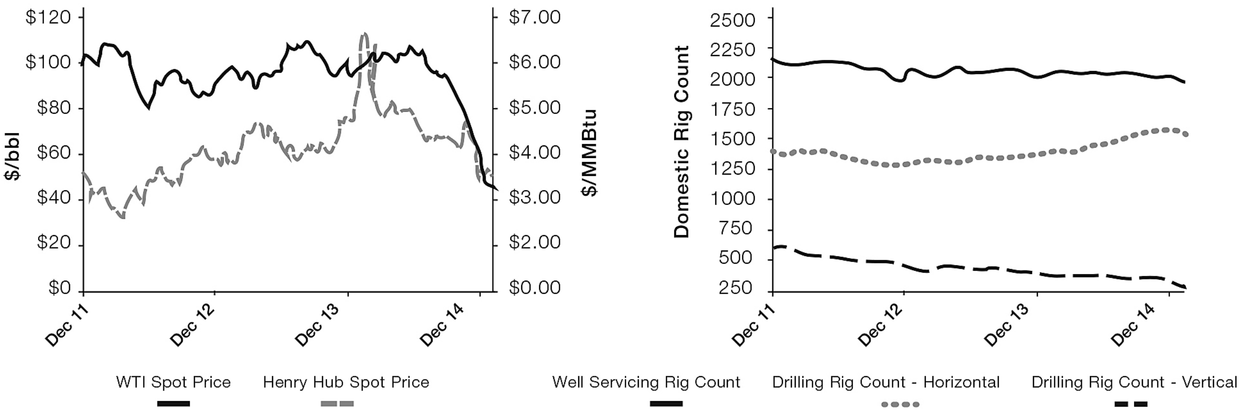
Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or operating expenditure.

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

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

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



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

Colombian oil prices have historically trended in line with West Texas Intermediate (WTI) oil prices. However, fluctuations in oil prices have a less significant impact on demand for drilling and production services in Colombia as compared to the impact on demand in North America. Demand for drilling and production services in Colombia is largely dependent upon its national oil company's long-term exploration and production programs.

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

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 this Annual Report on Form 10-K.

Competitive Strengths

Our competitive strengths include:

- *One of the Leading Providers in the Most Attractive Regions.* Our drilling rigs operate in many of the most attractive producing regions in the Americas, including the Bakken, Marcellus and Eagle Ford shales, and the Permian Basin, as well as Colombia. Our drilling rigs are located in six divisions throughout the United States and Colombia, diversifying our geographic exposure and limiting the impact of any regional slowdown. We believe the varied capabilities of our drilling rigs make them well suited to these areas where the optimal rig configuration is dictated by local geology and market conditions.

- *High Quality Assets.* Excluding all of the drilling rigs that we expect to sell in the near-term, over 85% of our drilling fleet was purchased or built new within the last 15 years, ten of which are AC drilling rigs which we constructed during 2011 to 2013. Additionally, we are currently constructing five new-build 1,500 horsepower AC drilling rigs which we expect to deliver and begin operating under long-term drilling contracts in 2015. Over 90% of our drilling rigs, excluding those that we expect to sell, are capable of drilling horizontal wells, and approximately 75% are equipped with either a walking or skidding system for pad drilling. Over 75% of our production services assets have been built since 2007, and all of our well servicing rigs have at least 550 horsepower. We believe that our modern and well maintained fleet allows us to realize higher contract and utilization rates because we are able to offer our clients equipment that is more reliable and requires less downtime than older equipment.

- *Provide Services Throughout the Well Life Cycle*. By offering our clients both drilling and production services, we capture revenue throughout the life cycle of a well and diversify our business. Our Drilling Services Segment performs work prior to initial production, and our Production Services Segment provides services such as logging, completion, perforation, workover and maintenance throughout the productive life of a well. We also provide certain end-of-well-life activities such as plugging and abandonment. Drilling and production services activity have historically exhibited different degrees of demand fluctuation, and we believe the diversity of our services reduces our exposure to decreases in demand for any single service activity. Further, the diversity of our service offerings enables us to cross-sell our services, benefiting our clients, allowing us to generate more business from existing clients and increasing our profits as we expand our services within existing markets.

- *Excellent Safety Record.* Our 2014 total recordable incident rate was one of the lowest we have achieved since our company's inception. Our safety program called “LiveSafe” focuses on creating an environment where everyone is committed to and recognizes the possibility of always working without incident or injury. We believe that by building strong relationships among our people, we can achieve an excellent safety record. Our excellent safety record and reputation are critical to winning new business and expanding our relationships with existing clients. Our commitment to safety helps us to keep our employees safe and reduces our business risk.

- *Experienced Management Team.* We believe that important competitive factors in establishing and maintaining long-term client relationships include having an experienced and skilled management team and maintaining employee continuity. Our CEO, Wm. Stacy Locke, joined Pioneer in 1995 as President and has over 35 years of industry experience. Our President of Drilling Services, Brian Tucker, and our President of Production Services, Joe Eustace, have over 45 years of combined oilfield services experience. Our management team has operated through numerous oilfield services cycles and provides us with valuable long-term experience and a detailed understanding of client requirements. We also seek to maximize employee continuity and minimize employee turnover by maintaining modern equipment, a strong safety record, ongoing growth and competitive compensation. We have devoted, and will continue to devote, substantial resources to our employee safety and training programs and maintaining low employee turnover.

- *Longstanding and Diversified Clients.* We maintain long-standing, high quality client relationships with a diverse group of large independent oil and gas exploration and production companies including Whiting Petroleum Corporation, which accounted for approximately 11.9% of our 2014 consolidated revenues, Apache Corporation, Hess Corporation, Penn Virginia Oil & Gas, LP and Continental Resources. We also maintain a good relationship with Ecopetrol, which accounted for approximately 9.9% of our 2014 consolidated revenues. We believe our relationships with our clients are strong and offer numerous opportunities for future growth.

Strategy

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

- *Competitive Position in the Most Attractive Domestic Markets.* Shale plays and non-shale oil or liquid rich environments are increasingly important to domestic hydrocarbon production, and not all drilling rigs are capable of successfully drilling in these unconventional opportunities. We are currently operating in the Bakken, Marcellus and Eagle Ford shales and the Permian Basin. All of the ten drilling rigs we constructed in 2011 to 2013 are currently operating in domestic shale and unconventional plays and we expect that our five new-build drilling rigs currently under construction will be deployed to these regions as well. Additionally, we have added significant capacity in recent years to our production services fleets, which we believe are well positioned to further capitalize on shale development.

- *Exposure to Oil and Liquids Rich Natural Gas Drilling Activity.* We believe that our flexible drilling and production services fleets allow us to pursue varied opportunities, enabling us to focus on a favorable mix of natural gas, oil and liquids rich natural gas activity. With natural gas prices at historically low levels in recent years, we intentionally increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions. With the recent decline in oil prices, we believe our fleets are highly capable and well positioned for deployment to whichever market is most profitable.

- *International Presence.* In 2007, we began operating in Colombia after a comprehensive review of international opportunities wherein we determined that Colombia offered an attractive mix of favorable business conditions, political stability, and a long-term commitment to expanding national oil and gas production. Four of our drilling rigs in Colombia are currently working under term contracts that extend through mid-2015 and we are actively marketing our other four rigs to multiple clients to diversify our client base in Colombia.

- *Growth Through Select Capital Deployment.* We have historically invested in the growth of our business by strategically upgrading our existing assets, selectively engaging in new-build opportunities, and through selective acquisitions. We have continued to make significant investments in the growth of our business over the past several years. We acquired a coiled tubing services business to expand our existing production services offerings at the end of 2011. Since the beginning of 2010, we have added significant capacity to our other production services fleets through the addition of 65 wireline units, 43 well servicing rigs and we have constructed ten AC drilling rigs, all of which are currently operating in domestic shale or unconventional plays. We are currently constructing five new-build AC rigs which we expect to deliver and begin operating under long-term drilling contracts in 2015.

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

Overview of Our Segments and Services

Drilling Services Segment

There are numerous factors that differentiate land drilling rigs, including their power generation systems and their drilling depth capabilities. A land drilling rig consists of engines, a hoisting system, a rotating system, pumps and related equipment to circulate drilling fluid, blowout preventers and related equipment. Generally, drilling rigs operate with crews of five to six persons.

Diesel or gas engines are typically the main power sources for a drilling rig. Power requirements for drilling jobs may vary considerably, but most land drilling rigs employ two or more engines to generate between 500 and 2,000 horsepower, depending on well depth and rig design. Most drilling rigs capable of drilling in deep formations, involving depths greater than 15,000 feet, use diesel-electric power units to generate and deliver electric current through cables to electrical switch gears, then to direct-current electric motors attached to the equipment in the hoisting, rotating and circulating systems.

Generally, a drilling rig's hoisting system is made up of a mast, or derrick, a traveling block and hook assembly that attaches to the rotating system, a mechanism known as the drawworks, a drilling line and ancillary equipment. The drawworks mechanism consists of a revolving drum, around which the drilling line is wound, and a series of shafts, clutches and chain and gear drives for generating speed changes and reverse motion. The drawworks also houses the main brake, which has the capacity to stop and sustain the weights used in the drilling process. When heavy loads are being lowered, a hydraulic or electric auxiliary brake assists the main brake to absorb the great amount of energy developed by the mass of the traveling block, hook assembly, drill pipe, drill collars and drill bit or casing being lowered into the well.

The rotating equipment from top to bottom consists of a top drive or a swivel, the kelly, and kelly bushing, the rotary table, drill pipe, drill collars and the drill bit. We refer to the equipment between the top drive or swivel and the drill bit as the drill stem. In a top drive system, the top drive hangs from a hook at the bottom of the traveling block. The top drive has a passageway for drilling mud to get into the drill pipe, and it has a heavy-duty electric motor connected to a threaded drive shaft which connects to and rotates the drill pipe. In a kelly drive system, the swivel assembly sustains the weight of the drill stem, permits its rotation and affords a rotating pressure seal and passageway for circulating drilling fluid into the top of the drill string. The swivel also has a large handle that fits inside the hook assembly at the bottom of the traveling block. Drilling fluid enters the drill stem through a hose, called the rotary hose, attached to the side of the swivel. The kelly is a triangular, square or hexagonal piece of pipe, usually 40 feet long, that transmits torque from the rotary table to the drill stem and permits its vertical movement as it is lowered into the hole. The bottom end of the kelly fits inside a corresponding triangular, square or hexagonal opening in a device called the kelly bushing. The kelly bushing, in turn, fits into a part of the rotary table called the master bushing. As the master bushing rotates, the kelly bushing also rotates, turning the kelly, which rotates the drill pipe and thus the drill bit. Drilling fluid is pumped through the kelly on its way to the bottom. The rotary table, equipped with its master bushing and kelly bushing, supplies the necessary torque to turn the drill stem. The drill pipe and drill collars are both steel tubes through which drilling fluid can be pumped. Drill pipe, sometimes called drill string, comes in 30-foot sections, or joints, with threaded sections on each end. Drill collars are heavier than drill pipe and both are threaded on the ends. Collars are used on the bottom of the drill stem to apply weight to the drilling bit. At the end of the drill stem is the bit, which chews up the formation rock and dislodges it so that drilling fluid can circulate the fragmented material back up to the surface where the circulating system filters it out of the fluid.

Drilling fluid, often called mud, is a mixture of clays, chemicals and water or oil, which is carefully formulated for the particular well being drilled. Drilling mud accounts for a major portion of the cost incurred and equipment used in drilling a well. Bulk storage of drilling fluid materials, the pumps and the mud-mixing equipment are placed at the start of the circulating system. Working mud pits and reserve storage are at the other end of the system. Between these two points, the circulating system includes auxiliary equipment for drilling fluid maintenance and equipment for well pressure control. Within the system, the drilling mud is typically routed from the mud pits to the mud pump and from the mud pump through a standpipe and the rotary hose to the drill stem. The drilling mud travels down the drill stem to the bit, up the annular space between the drill stem and the borehole and through the blowout preventer stack to the return flow line. It then travels to a shale shaker for removal of rock cuttings, and then back to the mud pits, which are usually steel tanks. The reserve pits, usually one or two fairly shallow excavations, are used for waste material and excess water around the location.

Drilling rigs use long strings of drill pipe and drill collars to drill wells. Drilling rigs are also used to set heavy strings of large-diameter pipe, or casing, inside the borehole. Because the total weight of the drill string and the casing can exceed 500,000 pounds, drilling rigs require significant hoisting and braking capacities. The actual drilling depth capability of a rig may be less than or more than its rated depth capability due to numerous factors, including the size, weight and amount of the drill pipe on the rig. The intended well depth and the drill site conditions determine the amount of drill pipe and other equipment needed to drill a well.

Technological advancements and trends in our industry affect the demand for certain types of equipment. In a continuing effort to improve our drilling rig fleet, we have installed top drives on 41 rigs (with seven additional spare top drives available for installation), iron roughnecks on 42 rigs (with 16 additional spare iron roughnecks available for installation), walking/skidding systems on 31 rigs and automatic catwalks on 33 rigs. These upgrades provide our clients with drilling rigs that have more varied capabilities for drilling in unconventional plays, and they improve our efficiency and safety.

In horizontal well drilling, operators can utilize top drives to reach formations that may not be accessible with conventional rotary drilling. Top drives provide maximum torque and rotational control, improved well control and better hole conditioning. In recent years, oil and gas exploration and production companies have increased the use of "pad drilling" whereby a series of horizontal wells are drilled in succession by a walking or skidding drilling rig at a single pad-site location. Walking systems increase efficiency by allowing multiple wells to be drilled on the same pad site and permitting the drilling rig to move between wells while drill pipe remains in the derrick, thus reducing move times and costs. Our walking system enables the drilling rig to move forward, backward, and side to side which affords the operator additional flexibility.

An iron roughneck is a remotely operated pipe handling feature on the rig floor, which is used to help reduce the occurrence of repetitive motion injuries and decrease drill pipe tripping time. An automated catwalk is a drill pipe handling feature used to raise drill pipe, drill collars, casing, and other necessary items to the drilling rig floor. Its function significantly reduces pick up and lay down time, thereby decreasing operator costs for handling casing.

The following table sets forth historical information regarding utilization for our drilling rig fleet:

	Year ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Average number of operating rigs for the period	62.0	68.2	65.0	69.3	71.0
Average utilization rate	87%	84%	87%	73%	59%

As of December 31, 2014, we had 53 drilling rigs in our fleet and nine drilling rigs classified as held for sale which were idle as of year-end. We expect to place a total of 15 additional rigs as held for sale during the first quarter of 2015. Excluding the rigs which we expect to sell in the near-term and considering the five new-build drilling rigs under construction, we expect to end 2015 with a drilling fleet of 43 rigs. The following is a summary of our drilling rig counts as of December 31, 2014 and February 1, 2015, as well as our expected count at March 31, 2015.

	Drilling Rigs Owned	**Drilling Rigs Held for Sale**	**Drilling Rig Fleet Count**
As of December 31, 2014	62	(9)	53
As of February 1, 2015	59	(12)	47
Expected at March 31, 2015	56	(18)	38

We believe that our drilling rigs and other related equipment are in good operating condition. Our employees perform periodic maintenance and minor repair work on our drilling rigs. We rely on various oilfield service companies for major repair work and overhaul of our drilling equipment when needed. We also engage in periodic improvement and upgrades of our drilling equipment. In the event of major breakdowns or mechanical problems, our rigs could be subject to significant idle time and a resulting loss of revenue if the necessary repair services are not immediately available.

Our drilling contracts generally provide for compensation on either a daywork or turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. Spot market contracts generally provide for the drilling of a single well and typically permit the client to terminate on short notice. We enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand. Currently, we have contracts with original terms of six months to four years in duration.

As of February 1, 2015, we have 29 drilling rigs earning under term contracts, which if not renewed prior to the end of their terms, will expire as follows:

		Term Contract Expiration by Period				
	Total Term Contracts	Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years	2 to 4 Years
United States	25	13	6	4	2	—
Colombia	4	4	—	—	—	—
	29	17	6	4	2	—

In response to the dramatic decline in oil prices during recent months, we have received early termination notices for 12 of our 29 drilling rigs that are earning revenues under term contracts. These 12 drilling rigs will be released upon completion of their current wells, all of which are expected to be completed by the end of the first quarter 2015, resulting in approximately $43.5 million of early termination payments which will be recognized as revenue over the remaining term of the contracts, $0.3 million of which was recognized in 2014.

As a provider of contract land drilling services, our business and the profitability of our operations depend on the level of drilling activity by oil and gas exploration and production companies operating in the geographic markets where we operate. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. During periods of reduced drilling activity or excess rig capacity, price competition tends to increase and the profitability of daywork contracts tends to decrease, and in such a competitive price environment, we may be more inclined to enter into turnkey contracts that expose us to greater risk of loss but which offer higher potential contract profitability.

During the last three fiscal years, our drilling contracts have primarily been for daywork drilling. The following table presents, by type of contract, information about the total number of wells we completed for our clients during each of the last three fiscal years.

	Year ended December 31,		
Types of Contracts	2014	2013	2012
Daywork	1,001	970	881
Turnkey	106	27	11
Total number of wells	1,107	997	892

Daywork Contracts. Under daywork drilling contracts, we provide a drilling rig and required personnel to our client who supervises the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is used. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the client bears a large portion of the out-of-pocket drilling costs and we generally bear no part of the usual risks associated with drilling, such as time delays and unanticipated costs.

Turnkey Contracts. Under a turnkey contract, we agree to drill a well for our client to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide technical expertise and engineering services, as well as most of the equipment and drilling supplies required to drill the well. We often subcontract for related services, such as the provision of casing crews, cementing and well logging. Under typical turnkey drilling arrangements, we do not receive progress payments and are paid by our client only after we have performed the terms of the drilling contract in full.

The risks to us under a turnkey contract are substantially greater than on a well drilled on a daywork basis. This is primarily because under a turnkey contract we assume most of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalations and personnel. We employ or contract for engineering expertise to analyze seismic, geologic and drilling data to identify and reduce some of the drilling risks we assume. We use the results of this analysis to evaluate the risks of a proposed contract and seek to account for such risks in our bid preparation. We believe that our operating experience, qualified drilling personnel, risk management program, internal engineering expertise and access to proficient third-party engineering contractors have allowed us to reduce some of the risks inherent in turnkey drilling operations. We also maintain insurance coverage against some, but not all, drilling hazards. However, the occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey jobs could have a material adverse effect on our financial position and results of operations.

Production Services Segment

Well Servicing. Our well servicing rig fleet provides a range of services, including the completion of newly-drilled wells, maintenance and workover of existing wells, and plugging and abandonment of wells at the end of their useful lives.

Newly drilled wells require completion services to prepare the well for production. Well servicing rigs are frequently used to complete newly drilled wells to minimize the use of higher cost drilling rigs in the completion process. The completion process may involve selectively perforating the well casing in the productive zones to allow oil or gas to flow into the well bore, stimulating and testing these zones and installing the production string and other downhole equipment. The completion process typically requires a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment. Accordingly, completion services require less well-to-well mobilization of equipment and can provide higher operating margins than regular maintenance work. The demand for completion services is directly related to drilling activity levels, which are sensitive to changes in oil and gas prices.

Regular maintenance is required throughout the life of a well to sustain optimal levels of oil and gas production. Common maintenance services include repairing inoperable pumping equipment in an oil well and replacing defective tubing in a gas well. Our maintenance services involve relatively low-cost, short-duration jobs which are part of normal well operating costs. The need for maintenance does not directly depend on the level of drilling activity, although it is somewhat impacted by short-term fluctuations in oil and gas prices. Accordingly, maintenance services generally experience relatively stable demand; however, when oil or gas prices are too low to justify additional expenditures, operating companies may choose to temporarily shut in producing wells rather than incur additional maintenance costs.

In addition to periodic maintenance, producing oil and gas wells occasionally require major repairs or modifications called workovers, which are typically more complex and more time consuming than maintenance operations. Workover services include extensions of existing wells to drain new formations either through perforating the well casing to expose additional productive zones not previously produced, deepening well bores to new zones or the drilling of lateral well bores to improve reservoir drainage patterns. Our well servicing rigs are also used to convert former producing wells to injection wells through which water or carbon dioxide is then pumped into the formation for enhanced oil recovery operations. Workovers also include major subsurface repairs such as repair or replacement of well casing, recovery or replacement of tubing and removal of foreign objects from the well bore. These extensive workover operations are normally performed by a well servicing rig with additional specialized auxiliary equipment, which may include rotary drilling equipment, mud pumps, mud tanks and fishing tools, depending upon the particular type of workover operation. All of our well servicing rigs are designed to perform complex workover operations. A workover may require a few days to several weeks and generally requires additional auxiliary equipment. The demand for workover services is sensitive to oil and gas producers' intermediate and long-term expectations for oil and gas prices.

Well servicing rigs are also used in the process of permanently closing oil and gas wells no longer capable of producing in economic quantities. Many well operators bid this work on a "turnkey" basis, requiring the service company to perform the entire job, including the sale or disposal of equipment salvaged from the well as part of the compensation received, and complying with state regulatory requirements. Plugging and abandonment work can provide favorable operating margins and is less sensitive to oil and gas pricing than drilling and workover activity since well operators must plug a well in accordance with state regulations when it is no longer productive. We perform plugging and abandonment work throughout our core areas of operation in conjunction with equipment provided by other service companies.

We typically bill clients for our well servicing on an hourly basis during the period that the rig is actively working. As of February 1, 2015, our fleet of well servicing rigs totaled 117 rigs, which we operate through 11 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota. Our fleet is among the newest in the industry, consisting of 107 rigs with 550 horsepower and 10 rigs with 600 horsepower capable of working at depths of 20,000 feet.

Wireline Services. Wireline trucks, like well servicing rigs, are utilized throughout the life of a well. Wireline trucks are often used in place of a well servicing rig when there is no requirement to remove tubulars from the well in order to make repairs.

Wireline services typically utilize a single truck equipped with a spool of wireline that is used to lower and raise a variety of specialized tools in and out of the wellbore. Electric wireline contains a conduit that allows signals to be transmitted to or from tools located in the well. These tools can be used to measure pressures and temperatures as well as the condition of the casing and the cement that holds the casing in place. In order for oil and gas exploration and production companies to better understand the reservoirs they are drilling or producing, they require logging services to accurately characterize reservoir rocks and fluids. We provide both open and cased-hole logging services, including the latest pulsed-neutron technology.

Other applications for wireline tools include placing equipment in or retrieving equipment from the wellbore, installing bridge plugs, perforating the casing in order to prepare the well for production, or cutting off pipe that is stuck in the well so that the free section can be recovered.

As of February 1, 2015, our wireline services fleet totaled 128 wireline units, including six offshore units, which we operate through 24 locations in Texas, Kansas, Colorado, Montana, North Dakota, Louisiana, Oklahoma and Wyoming.

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 February 1, 2015, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are currently deployed through three locations in Texas and Louisiana.

Seasonality

All our production services operations are impacted by seasonal factors. Our business can be negatively impacted during the winter months due to inclement weather, fewer daylight hours, and holidays. Because our well servicing rigs, wireline units and coiled tubing units are mobile, during periods of heavy snow, ice or rain, we may not be able to move our equipment between locations.

Clients

We provide drilling and production services to numerous major and independent oil and gas exploration and production companies that are active in the geographic areas in which we operate. The following table shows our three largest clients as a percentage of our total revenue for each of our last three fiscal years.

	Total Revenue Percentage
Fiscal year ended December 31, 2014	
Whiting Petroleum Company	11.9%
Ecopetrol	9.9%
Penn Virginia Oil & Gas, LP	6.0%
Fiscal year ended December 31, 2013	
Whiting Petroleum Company	12.6%
Ecopetrol	10.7%
Apache Corporation	5.9%
Fiscal year ended December 31, 2012	
Whiting Petroleum Company	10.1%
Ecopetrol	9.7%
Apache Corporation	5.5%

Competition

Drilling Services Segment

We encounter substantial competition from other drilling contractors. Our primary market areas are highly fragmented and competitive. The fact that drilling rigs are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry.

The drilling contracts we compete for are usually awarded on the basis of competitive bids. Our principal competitors are Helmerich & Payne, Inc., Precision Drilling Trust, Patterson-UTI Energy, Inc. and Nabors Industries, Ltd. In addition to pricing and rig availability, we believe the following factors are also important to our clients in determining which drilling contractors to select:

- the type and condition of each of the competing drilling rigs;
- the mobility and efficiency of the rigs;
- the quality of service and experience of the rig crews;
- the safety records of our company;
- the offering of ancillary services; and
- the ability to provide drilling equipment adaptable to, and personnel familiar with, new technologies and drilling techniques.

While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, our safety record, our ability to offer ancillary services, the experience of our rig crews and the quality of service we provide to differentiate us from our competitors.

Drilling companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling services improves in a region where we operate, our competitors might respond by moving in suitable rigs from other regions. An influx of rigs from other regions could rapidly intensify competition and make any improvement in demand for drilling rigs in a particular region short-lived.

Some of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to:

- better withstand industry downturns;
- compete more effectively on the basis of price and technology;
- better retain skilled rig personnel; and
- build new rigs or acquire and refurbish existing rigs and place them into service more quickly than us in periods of high drilling demand.

Production Services Segment

The market for production services is highly competitive. Competition is influenced by such factors as price, capacity, availability of work crews, type and condition of equipment and reputation and experience of the service provider, including safety record. We believe that an important competitive factor in establishing and maintaining long-term client relationships is having an experienced, skilled and well-trained work force. In recent years, many of our larger clients have placed increased emphasis on the safety performance and quality of the crews, equipment and services provided by their contractors. We have devoted, and will continue to devote, substantial resources toward employee safety and training programs. Although we believe clients consider all of these factors, price is generally the primary factor in determining which service provider is awarded the work. However, we believe that many clients are willing to pay a slight premium for the quality and safe, efficient service we provide.

The largest well servicing providers that we compete with are Key Energy Services, Basic Energy Services, Nabors Industries, Superior Energy Services, Inc. and CC Forbes. In addition, there are numerous smaller companies that compete in our well servicing markets.

The wireline market is dominated by Schlumberger Ltd. and Halliburton Company. These companies have a substantially larger asset base than we do and operate in all major U.S. oil and natural gas producing basins. Other competitors include Weatherford International, Baker Hughes, Superior Energy Services, Basic Energy Services, and C&J Energy Services. The market for wireline services is very competitive, but historically we have competed effectively with our competitors based on performance and strong client service.

The market for coiled tubing has increased due to the growth in deep well and horizontal drilling. Our primary competitors in the coiled tubing services market include Schlumberger Ltd., Baker Hughes, Halliburton Company, Key Energy Services, RPC Inc. and Superior Energy Services, Inc. In addition, numerous small companies compete in our coiled tubing services markets in the United States.

The need for well servicing, wireline and coiled tubing services fluctuates primarily in relation to the price (or anticipated price) of oil and natural gas, which in turn is driven by the supply of and demand for oil and natural gas. Generally, as supply of these commodities decreases and demand increases, service and maintenance requirements increase as oil and natural gas producers attempt to maximize the productivity of their wells in a higher priced environment.

The level of our revenues, earnings and cash flows are substantially dependent upon, and affected by, the level of domestic and international oil and gas exploration and development activity, as well as the equipment capacity in any particular region. For a more detailed discussion, see Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Raw Materials

The materials and supplies we use in our drilling and production services operations include fuels to operate our equipment, drilling mud, drill pipe, drill collars, drill bits and cement. We do not rely on a single source of supply for any of these items. While we are not currently experiencing any shortages, from time to time there have been shortages of drilling equipment and supplies during periods of high demand. Shortages could result in increased prices for drilling equipment or supplies that we may be unable to pass on to clients. In addition, during periods of shortages, the delivery times for equipment and supplies can be substantially longer. Any significant delays in obtaining drilling equipment or supplies could limit our drilling operations and jeopardize our relations with clients. In addition, shortages of drilling equipment or supplies could delay and adversely affect our ability to obtain new contracts for our drilling rigs, which could have a material adverse effect on our financial condition and results of operations.

Operating Risks and Insurance

Our operations are subject to the many hazards inherent in the contract land drilling business, including the risks of:

- blowouts;
- fires and explosions;
- loss of well control;
- collapse of the borehole;
- lost or stuck drill strings; and
- damage or loss from natural disasters.

Any of these hazards can result in substantial liabilities or losses to us from, among other things:

- suspension of drilling operations;
- damage to, or destruction of, our property and equipment and that of others;
- personal injury and loss of life;
- damage to producing or potentially productive oil and gas formations through which we drill; and
- environmental damage.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include pollution liability in excess of relatively low limits. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our clients. However, clients who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a client to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

Our current insurance coverage includes property insurance on our rigs, drilling equipment, production services equipment and real property. Our insurance coverage for property damage to our rigs, drilling equipment and production services equipment is based on our estimates of the cost of comparable used equipment to replace the insured property. The policy provides for a deductible on drilling rigs of $500,000 per occurrence ($750,000 deductible for rigs with an insured value greater than $10 million), and a deductible on production services equipment of $250,000 per occurrence. Our third-party liability insurance coverage is $101 million per occurrence and in the aggregate, with a deductible of $250,000 per occurrence. We also carry insurance coverage for pollution liability up to $20 million with a deductible of $500,000. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. However, such insurance may not be sufficient to protect us against liability for all consequences of well disasters, extensive fire damage or damage to the environment.

In addition, we generally carry insurance coverage to protect against certain hazards inherent in our turnkey contract drilling operations. This insurance covers "control-of-well," including blowouts above and below the surface, redrilling, seepage and pollution. This policy provides coverage of $3 million, $5 million, $10 million, $15 million or $20 million, subject to a deductible of $150,000 or $250,000, depending on the area in which the well is drilled and its target depth. This policy also provides care, custody and control insurance, with a limit of $1 million, subject to a $100,000 deductible.

Employees

We currently have approximately 3,400 employees. The majority of our employees work in operations for our Drilling Services Segment and Production Services Segment and are primarily compensated on an hourly basis. The number of employees in operations fluctuates depending on the utilization of our drilling rigs, well servicing rigs, wireline units and coiled tubing units at any particular time. None of our employment arrangements are subject to collective bargaining arrangements.

Our operations require the services of employees having the technical training and experience necessary to achieve proper operational standards. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Although we have not encountered material difficulty in hiring and retaining employees in our operations, shortages of qualified personnel have occurred in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. While we believe our wage rates are competitive and our relationships with our employees are satisfactory, a significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material adverse effect on our financial condition and results of operations.

Facilities

We lease our corporate office facilities located at 1250 N.E. Loop 410, Suite 1000 San Antonio, Texas 78209. We conduct our business operations through 66 other real estate locations, of which we own 15, in the United States (Texas, Oklahoma, Colorado, Utah, Montana, North Dakota, Pennsylvania, Wyoming, Mississippi, Arkansas, Louisiana and Kansas) and internationally in Colombia. These real estate locations are primarily used for regional offices and storage and maintenance yards.

Governmental Regulation

Our operations are subject to stringent federal, state and local laws, rules and regulations governing the protection of the environment and human health and safety. Some of those laws, rules and regulations relate to the disposal of hazardous substances, oilfield waste and other waste materials and restrict the types, quantities and concentrations of those substances that can be released into the environment. Several of those laws also require removal and remedial action and other cleanup under certain circumstances, commonly regardless of fault. Our operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, the federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Safe Drinking Water Act, or SDWA, the federal Outer Continental Shelf Lands Act, the Occupational Safety and Health Act, or OSHA, and their state counterparts and similar statutes are the primary statutes that impose the requirements described above and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. The OSHA hazard communication standard, the Environmental Protection Agency "community right-to-know" regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and report information about the hazardous materials we use in our operations to employees, state and local government authorities and local citizens. In addition, CERCLA, also known as the "Superfund" law, and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release or threatened release of hazardous substances into the environment. These persons include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

Environmental laws and regulations are complex and subject to frequent change. Failure to comply with governmental requirements or inadequate cooperation with governmental authorities could subject a responsible party to administrative, civil or criminal action. We may also be exposed to environmental or other liabilities originating from businesses and assets which we acquired from others. Our compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination or regulatory noncompliance may require us to make material expenditures or subject us to liabilities that we currently do not anticipate.

There are a variety of regulatory developments, proposals or requirements and legislative initiatives that have been introduced in the United States and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments are the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol" (an internationally applied protocol, which has been ratified in Colombia, which is a location where we provide drilling services), the Regional Greenhouse Gas Initiative or "RGGI" in the Northeastern United States, and the Western Regional Climate Action Initiative in the Western United States.

The U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases.

In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act. On December 7, 2009, the EPA responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from motor vehicles contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change.

Based on these findings, in 2010 the EPA adopted two sets of regulations that restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of greenhouse gases from motor vehicles and another that requires certain construction and operating permit reviews for greenhouse gas emissions from certain large stationary sources. The stationary source final rule addresses the permitting of greenhouse gas emissions from stationary sources under the Clean Air Act Prevention of Significant Deterioration construction and Title V operating permit programs, pursuant to which these permit programs have been "tailored" to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. In addition, the EPA adopted rules requiring the monitoring and reporting of greenhouse gases from certain sources, including, among others, onshore oil and natural gas production facilities.

In April 2012, the EPA issued regulations specifically applicable to the oil and gas industry that will require operators to significantly reduce volatile organic compounds, or VOC, emissions from natural gas wells that are hydraulically fractured through the use of "green completions" to capture natural gas that would otherwise escape into the air. The EPA also issued regulations that establish standards for VOC emissions from several types of equipment at natural gas well sites, including storage tanks, compressors, dehydrators and pneumatic controllers.

On June 2, 2014, the EPA issued a proposed rule to limit carbon dioxide emissions from existing electric utility generating units. Under the EPA's current proposal, nationwide emissions of carbon dioxide from the power sector would be cut by up to 30% from the 2005 baseline by the year 2030. The required emission reductions would vary state-by-state, and the proposed rule provides each State flexibility in determining how the emission reductions would be achieved.

On January 14, 2015, the EPA announced that it plans to implement additional steps to reduce methane and VOC emissions from the oil and gas industry. Proposed regulations are planned for the summer of 2015 and are expected to address new and modified oil and gas sources, but may also be extended to certain existing sources located in areas not meeting federal standards for ozone.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows. In addition, these developments could curtail the demand for fossil fuels such as oil and gas in areas of the world where our clients operate and thus adversely affect demand for our services, which may in turn adversely affect our future results of operations. Finally, we cannot predict with any certainty whether changes to temperature, storm intensity or precipitation patterns as a result of climate change will have a material impact on our operations.

Hydraulic fracturing is a commonly used process that involves injection of water, sand, and a minor amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. Several proposals are being considered by the EPA and other federal agencies that, if implemented, would impose additional requirements on the practice of hydraulic fracturing. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to concerns regarding potential environmental and physical impacts, including groundwater and drinking water impacts, as well as whether such activities may cause minor earthquakes.

The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act (SDWA) to exclude certain hydraulic fracturing practices from the definition of "underground injection." The EPA has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and has developed draft guidance relating to such practices. In addition, repeal of the SDWA exclusion of hydraulic fracturing has been advocated by certain advocacy organizations and others in the public. Congress has from time to time considered legislation to repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate new regulations and permitting requirements for hydraulic fracturing, and to require the disclosure of the chemical constituents of hydraulic fracturing fluids to a regulatory agency, which would make the information public via the Internet.

Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing. A Progress Report was issued by the EPA in May 2014; peer review of the information provided in the Progress Report is underway. In addition, in April 2012, the EPA issued the first federal air standards for natural gas wells that are hydraulically fractured, which will require operators to significantly reduce VOC emissions through the use of "green completions" to capture natural gas that would otherwise escape into the air. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or "green") completions must be used. The rules also establish specific new requirements, which were effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On September 23, 2013, the EPA published amendments to the rule which would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. On December 19, 2014, the EPA published a final rule clarifying certain aspects of the new rules. On January 14, 2015, the EPA announced that it plans to propose and implement new regulations to further reduce methane and VOC emissions from the oil and gas industry. It is also possible that the EPA will propose additional amendments to its existing oil and gas regulations. These rules may require a number of modifications to our clients' and our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our clients, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

The EPA is also developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by early 2015. The U.S. Department of the Interior has also proposed regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents and has conducted hearings on a possible rule to reduce flaring and venting associated with oil and gas operations on public lands.

In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, that would require, with some exceptions, disclosure of constituents of hydraulic fracturing fluids, or that would impose higher taxes, fees or royalties on natural gas production. Moreover, public debate over hydraulic fracturing and shale gas production continued to see strong public opposition, and has resulted in delays of well permits in some areas.

On June 30, 2014, the State of New York's Court of Appeals upheld the right of individual municipalities in the State of New York to ban hydraulic fracturing using zoning restrictions. In December 2014, New York State Governor Cuomo announced that hydraulic fracturing will be permanently banned in the state. Similarly situated municipalities in other states may seek to ban or restrict resource extraction operations within their borders using zoning restrictions, which could adversely affect the ability of resource extraction enterprises to operate in certain parts of the country, and thus adversely affect demand for our services, which may in turn adversely affect our future results of operations.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our clients. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our drilling and well servicing activities, any or all of which could adversely affect our financial position, results of operations and cash flows.

In addition, our business depends on the demand for land drilling and production services from the oil and gas industry and, therefore, is affected by tax, environmental and other laws relating to the oil and gas industry generally, by changes in those laws and by changes in related administrative regulations. It is possible that these laws and regulations may in the future add significantly to our operating costs or those of our clients, or otherwise directly or indirectly affect our operations.

Our wireline operations involve the use of radioactive isotopes along with other nuclear, electrical, acoustic, and mechanical devices. Our activities involving the use of isotopes are regulated by the U.S. Nuclear Regulatory Commission and specified agencies of certain states. Additionally, we use high explosive charges for perforating casing and formations, and we use various explosive cutters to assist in wellbore cleanout. Such operations are regulated by the U.S. Department of Justice, Bureau of Alcohol, Tobacco, Firearms, and Explosives and require us to obtain licenses or other approvals for the use of densitometers as well as explosive charges. We have obtained these licenses and approvals when necessary and believe that we are in substantial compliance with these federal requirements.

Among the services we provide, we operate as a motor carrier for the transportation of our own equipment and therefore are subject to regulation by the U.S. Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the U.S. Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations.

From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Available Information

Our Website address is *www.pioneeres.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, are available free of charge through our Website as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the Securities and Exchange Commission. The public may read and copy these materials at the Securities and Exchange Commission's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. For additional information on the operations of the Securities and Exchange Commission's Public Reference Room, please call 1-800-SEC-0330. In addition, the Securities and Exchange Commission maintains an Internet site at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers that file electronically. We have also posted on our Website our: Charters for the Audit, Compensation, and Nominating and Corporate Governance Committees of our Board; Code of Business Conduct and Ethics; Corporate Governance Guidelines; and Company Contact Information. Information on our website is not incorporated into this report or otherwise made part of this report.

Item 1A. Risk Factors

The information set forth in this Item 1A should be read in conjunction with the rest of the information included in this report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and the financial statements and related notes this report contains. While we attempt to identify, manage and mitigate risks and uncertainties associated with our business to the extent practical under the circumstances, some level of risk and uncertainty will always be present. Additional risks and uncertainties that are not presently known to us or that we currently believe are immaterial also may negatively impact our business, financial condition or operating results.

Set forth below are various risks and uncertainties that could adversely impact our business, financial condition, results of operations and cash flows.

Risks Relating to the Oil and Gas Industry

We derive all our revenues from companies in the oil and gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility of oil and gas prices.

As a provider of contract land drilling services and oil and gas production services, our business depends on the level of exploration and production activity in the geographic markets where we operate. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and gas prices, and market expectations of potential changes in those prices, significantly affect the levels of those activities. Oil and gas prices have been volatile historically and, we believe, will continue to be so in the future. Worldwide political, economic, and military events as well as natural disasters have contributed to oil and gas price volatility historically, and are likely to continue to do so in the future. Many factors beyond our control affect oil and gas prices, including:

- the foreign supply of oil and gas;
- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;
- available pipeline and other oil and gas transportation capacity;
- the levels of oil and gas storage;
- the ability of oil and gas exploration and production companies to raise capital;
- economic conditions in the United States and elsewhere;

- actions by the Organization of Petroleum Exporting Countries, which we refer to as OPEC;
- political instability in the Middle East and other major oil and gas producing regions;
- governmental regulations, both domestic and foreign;
- domestic and foreign tax policy;
- weather conditions in the United States and elsewhere;
- the pace adopted by foreign governments for the exploration, development and production of their national reserves;
- the price of foreign imports of oil and gas; and
- the overall supply and demand for oil and gas.

As a result of the recent declines in oil prices that began in late 2014 and have continued into 2015, our clients will likely reduce spending on exploration and production projects, resulting in a decrease in demand for our services.

Oil and natural gas prices, and market expectations of potential changes in these prices, significantly impact the level of worldwide drilling and production services activities. Reduced demand for oil and natural gas generally results in lower prices for these commodities and often impacts the economics of planned drilling projects and ongoing production projects, resulting in the curtailment, reduction, delay or postponement of such projects for an indeterminate period of time. When drilling and production activity and spending declines, both dayrates and utilization historically decline as well.

In recent months, beginning in October 2014, oil prices worldwide have dropped significantly. If the current depressed oil and natural gas prices persist for a prolonged period, or further decline, oil and gas exploration and production companies are likely to cancel or curtail their drilling programs and lower production spending on existing wells, thereby reducing demand for our services.

Any prolonged reduction in the overall level of exploration and development activities, whether resulting from changes in oil and gas prices or otherwise, could materially and adversely affect us by negatively impacting:

- our revenues, cash flows and profitability;
- the fair market value of our drilling rig fleet and production services equipment;
- our ability to maintain or increase our borrowing capacity;
- our ability to obtain additional capital to finance our business and make acquisitions, and the cost of that capital;
- the collectability of our receivables; and
- our ability to retain skilled rig personnel whom we would need in the event of an upturn in the demand for our services.

If any of the foregoing were to occur, it could have a material adverse effect on our business and financial results.

Risks Relating to Our Business

Reduced demand for or excess capacity of drilling services or production services could adversely affect our profitability.

Our profitability in the future will depend on many factors, but largely on pricing and utilization rates for our drilling and production services. A reduction in the demand for drilling rigs or an increase in the supply of drilling rigs, whether through new construction or refurbishment, could decrease the dayrates and utilization rates for our drilling services, which would adversely affect our revenues and profitability. An increase in supply of well servicing rigs, wireline units and coiled tubing units, without a corresponding increase in demand, could similarly decrease the pricing and utilization rates of our production services, which would adversely affect our revenues and profitability.

We operate in a highly competitive, fragmented industry in which price competition could reduce our profitability.

We encounter substantial competition from other drilling contractors and other oilfield service companies. Our primary market areas are highly fragmented and competitive. The fact that drilling and production services equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry and may result in an oversupply of equipment in an area. Contract drilling companies and other oilfield service companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling or production services improves in a region where we operate, our competitors might respond by moving in suitable rigs and production services equipment from other regions. An influx of equipment from other regions could rapidly intensify competition, reduce profitability and make any improvement in demand for drilling or production services short-lived.

Most drilling services contracts and production services contracts are awarded on the basis of competitive bids, which also results in price competition. In addition to pricing and equipment availability, we believe the following factors are also important to our clients in determining which drilling services or production services provider to select:

- the type and condition of each of the competing drilling rigs, well servicing rigs, wireline units and coiled tubing units;
- the mobility and efficiency of the equipment;
- the quality of service and experience of the crews;
- the safety record of the company providing the services;
- the offering of ancillary services; and
- the ability to provide drilling and production services equipment adaptable to, and personnel familiar with, new technologies and drilling and production techniques.

While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, our safety record, our ability to offer ancillary services, the experience of our crews and the quality of service we provide to differentiate us from our competitors. This strategy is less effective when lower demand for drilling and production services intensifies price competition and makes it more difficult for us to compete on the basis of factors other than price. In all of the markets in which we compete, an oversupply of drilling rigs or production services equipment can cause greater price competition, which can reduce our profitability.

We face competition from many competitors with greater resources.

Some of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to:

- better withstand industry downturns;
- compete more effectively on the basis of price and technology;
- retain skilled personnel; and
- build new rigs or acquire and refurbish existing rigs and place them into service more quickly than us in periods of high drilling demand.

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

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

Although we take measures to ensure that we use advanced technologies for drilling and production services equipment, changes in technology or improvements in our competitors' equipment could make our equipment less competitive or require significant capital investments to keep our equipment competitive, which could have an adverse effect on our financial condition and operating results.

We derive a significant portion of our revenue from a limited number of major clients, and our business, financial condition and results of operations could be materially adversely affected if we are unable to maintain relationships with these clients, or if their demand for our services decreases.

In the past, we have derived a significant portion of our revenue from a limited number of major clients. For the years ended December 31, 2014, 2013 and 2012, our drilling and production services to our top three clients accounted for approximately 28%, 29%, and 25%, respectively, of our revenue, and in 2014, 2013 and 2012, one client, Whiting Petroleum Company, accounted for 12%, 13% and 10%, respectively, of our revenue. The loss of one or more of our major clients, or their decrease in demand for our services, could have a material adverse effect on our business, financial condition and results of operations.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

Our indebtedness is primarily a result of the two production services businesses that we acquired in 2008 and the acquisition of Go-Coil in 2011. At February 1, 2015, our total debt balance of $450.1 million primarily consists of $300 million outstanding under our Senior Notes and $150 million outstanding under our Revolving Credit Facility. At February 1, 2015, we had borrowing availability of $181.5 million under our Revolving Credit Facility.

Our current and future indebtedness could have important consequences, including:

- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;
- making us more vulnerable to a downturn in our business, our industry or the economy in general as a substantial portion of our operating cash flow could be required to make principal and interest payments on our indebtedness, making it more difficult to react to changes in our business, industry and market conditions;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impairing our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;
- limiting our ability to obtain additional financing that may be necessary to operate or expand our business;
- putting us at a competitive disadvantage to competitors that have less debt; and
- increasing our vulnerability to rising interest rates.

We anticipate that our cash generated by operations, proceeds from the expected sales of certain non-strategic assets and our ability to borrow under the currently unused portion of our Revolving Credit Facility should allow us to meet our routine financial obligations for at least the next twelve months. However, our ability to make payments on our indebtedness, and to fund planned capital expenditures, will depend on our ability to generate cash in the future. This, to a certain extent, is subject to conditions in the oil and gas industry, general economic and financial conditions, competition in the markets where we operate, the impact of legislative and regulatory actions on how we conduct our business and other factors, all of which are beyond our control. If our business does not generate sufficient cash flow from operations to service our outstanding indebtedness, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;

- reducing or delaying acquisitions or capital investments, such as refurbishments of our rigs and related equipment; or
- seeking to raise additional capital.

However, we may be unable to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, and any such alternative financing plans might be insufficient to allow us to meet our debt obligations. If we are unable to generate sufficient cash flow or are otherwise unable to obtain the funds required to make principal and interest payments on our indebtedness, or if we otherwise fail to comply with the various covenants in our Revolving Credit Facility or other instruments governing any future indebtedness, we could be in default under the terms of our Revolving Credit Facility or such instruments. In the event of a default, the lenders under our Revolving Credit Facility could elect to declare all the loans made under such facility to be due and payable together with accrued and unpaid interest and terminate their commitments thereunder and we or one or more of our subsidiaries could be forced into bankruptcy or liquidation. Any of the foregoing consequences could materially and adversely affect our business, financial condition, results of operations and prospects.

Our Revolving Credit Facility and our Senior Notes impose significant covenants on us that may affect our ability to successfully operate our business.

Our Revolving Credit Facility limits our ability to take various actions, such as:

- limitations on the incurrence of additional indebtedness;
- restrictions on investments, capital expenditures, mergers or consolidations, asset dispositions, acquisitions, transactions with affiliates and other transactions without the lenders' consent; and
- limitation on dividends and distributions.

In addition, our Revolving Credit Facility requires us to maintain certain financial covenants and to satisfy certain financial conditions, which may require us to reduce our debt or take some other action in order to comply with them.

The Indenture governing our Senior Notes limits our and certain of our subsidiaries' ability to:

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

The failure to comply with any of these covenants would cause an event of default under our Revolving Credit Facility or our Senior Notes. An event of default, if not waived, could result in acceleration of the outstanding indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to pay our debt or borrow sufficient funds to refinance it. Even if new financing is available, it may not be available on terms that are acceptable to us. These covenants could also limit our ability to obtain future financing, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our Revolving Credit Facility and our Senior Notes.

Unexpected cost overruns on our turnkey drilling jobs could adversely affect our financial position and our results of operations.

We have historically derived a portion of our revenues from turnkey drilling contracts, and we expect turnkey contracts will continue to represent a component of our future revenues. The occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey jobs could have a material adverse effect on our financial position and results of operations. Under a typical turnkey drilling contract, we agree to drill a well for our client to a specified depth and under specified conditions for a fixed price. We provide technical expertise and engineering services, as well as most of the equipment and drilling supplies required to drill the well. We often subcontract for related services, such as the provision of casing crews, cementing and well logging. Under typical turnkey drilling arrangements, we do not receive progress payments and are paid by our client only after we have performed the terms of the drilling contract in full. For these reasons, the risk to us under a turnkey drilling contract is substantially greater than for a well drilled on a daywork basis because we must assume most of the risks associated with drilling operations that the operator generally assumes under a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalations and personnel. In addition, since we are only paid by our clients after we have performed the terms of the drilling contract in full, our liquidity can be affected by the number of turnkey contracts that we enter into.

Although we attempt to obtain insurance coverage to reduce certain of the risks inherent in our turnkey drilling operations, adequate coverage may be unavailable in the future and we might have to bear the full cost of such risks, which could have an adverse effect on our financial condition and results of operations.

Our operations involve operating hazards, which, if not insured or indemnified against, could adversely affect our results of operations and financial condition.

Our operations are subject to the many hazards inherent in the drilling and well servicing industries, including the risks of:

- blowouts;
- cratering;
- fires and explosions;
- loss of well control;
- collapse of the borehole;
- damaged or lost drilling equipment; and
- damage or loss from natural disasters.

Any of these hazards can result in substantial liabilities or losses to us from, among other things:

- suspension of operations;
- damage to, or destruction of, our property and equipment and that of others;
- personal injury and loss of life;
- damage to producing or potentially productive oil and gas formations through which we drill; and
- environmental damage.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include, among other things, pollution liability in excess of relatively low limits. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our clients. However, clients who provide contractual indemnification protection may not in all cases maintain adequate insurance or otherwise have the financial resources necessary to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a client to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may be unable to maintain adequate insurance in the future at rates we consider reasonable.

We could be adversely affected if shortages of equipment, supplies or personnel occur.

From time to time there have been shortages of drilling and production services equipment and supplies during periods of high demand which we believe could recur. Shortages could result in increased prices for drilling and production services equipment or supplies that we may be unable to pass on to clients. In addition, during periods of shortages, the delivery times for equipment and supplies can be substantially longer. Any significant delays in our obtaining drilling and production services equipment or supplies could limit drilling and production services operations and jeopardize our relations with clients. In addition, shortages of drilling and production services equipment or supplies could delay and adversely affect our ability to obtain new contracts for our rigs, which could have a material adverse effect on our financial condition and results of operations.

Our strategy of constructing drilling rigs during periods of peak demand requires that we maintain an adequate supply of drilling rig components to complete our rig building program. Our suppliers may be unable to continue providing us the needed drilling rig components if their manufacturing sources are unable to fulfill their commitments.

Our operations require the services of employees having the technical training and experience necessary to achieve the proper operational results. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Shortages of qualified personnel have occurred in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. A significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material adverse effect on our financial condition and results of operations.

Our acquisition strategy exposes us to various risks, including those relating to difficulties in identifying suitable acquisition opportunities and integrating businesses, assets and personnel, as well as difficulties in obtaining financing for targeted acquisitions and the potential for increased leverage or debt service requirements.

As a key component of our business strategy, we have pursued and intend to continue to pursue acquisitions of complementary assets and businesses. Our acquisition strategy in general, and our recent acquisitions in particular, involve numerous inherent risks, including:

- unanticipated costs and assumption of liabilities and exposure to unforeseen liabilities of acquired businesses, including environmental liabilities;
- difficulties in integrating the operations and assets of the acquired business and the acquired personnel;
- limitations on our ability to properly assess and maintain an effective internal control environment over an acquired business in order to comply with applicable periodic reporting requirements;
- potential losses of key employees and clients of the acquired businesses;
- risks of entering markets in which we have limited prior experience; and
- increases in our expenses and working capital requirements.

The process of integrating an acquired business may involve unforeseen costs and delays or other operational, technical and financial difficulties that may require a disproportionate amount of management attention and financial and other resources. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, we may not have sufficient capital resources to complete additional acquisitions. Historically, we have funded business acquisitions and the growth of our rig fleet through a combination of debt and equity financing. We may incur substantial additional indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with such acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity or convertible securities could be dilutive to our existing shareholders. Furthermore, we may not be able to obtain additional financing on satisfactory terms.

Even if we have access to the necessary capital, we may be unable to continue to identify additional suitable acquisition opportunities, negotiate acceptable terms or successfully acquire identified targets.

Our cash and cash equivalents and short term investments could be adversely affected if the financial institutions in which we hold our cash and cash equivalents fail.

We maintain cash balances at third-party financial institutions in excess of the Federal Deposit Insurance Corporation insurance limit. While we monitor the cash balances in the operating accounts and adjust the balances as appropriate, we may incur a loss to the extent such loss exceeds the insurance limitation, and there could be a material impact on our business, if one of more of the financial institutions with which we deposit fails or is subject to other adverse conditions in the financial or credit markets and bank regulators elect to impose losses on uninsured depositors. To date, we have experienced no loss or lack of access to our invested cash or cash equivalents. However, we can provide no assurance that access to our invested cash and cash equivalents will not be impacted by adverse conditions in the financial and credit markets.

Our international operations are subject to political, economic and other uncertainties not encountered in our domestic operations.

Our international operations are subject to political, economic and other uncertainties not generally encountered in our U.S. operations which include, among potential others:

- risks of war, terrorism, civil unrest and kidnapping of employees;
- employee strikes, work stoppages, labor disputes and other slowdowns;
- expropriation, confiscation or nationalization of our assets;
- renegotiation or nullification of contracts;
- foreign taxation, such as the tax for equality and the net-worth tax recently enacted in Colombia;
- the inability to repatriate earnings or capital due to laws limiting the right and ability of foreign subsidiaries to pay dividends and remit earnings to affiliated companies;
- changing political conditions and changing laws and policies affecting trade and investment;
- concentration of clients;
- regional economic downturns;
- the overlap of different tax structures;
- the burden of complying with multiple and potentially conflicting laws;
- the risks associated with the assertion of foreign sovereignty over areas in which our operations are conducted;
- the risks associated with any lack of compliance with the Foreign Corrupt Practices Act of 1977 ("FCPA") or other anti-corruption laws;
- the risks associated with fluctuating currency values, hard currency shortages and controls of foreign currency exchange;
- difficulty in collecting international accounts receivable; and
- potentially longer payment cycles.

Our international operations are concentrated in Colombia and currently all of our drilling contracts are with one client, Ecopetrol. We believe our relationship with Ecopetrol is good; however, the loss of this large client could have an adverse effect on our business, financial condition and result of operations.

Additionally, we may be subject to foreign governmental regulations favoring or requiring the awarding of contracts to local contractors or requiring foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These regulations could adversely affect our ability to compete.

We are committed to doing business in accordance with applicable anti-corruption laws and our code of conduct and ethics. We are subject, however, to the risk that our employees and agents may take action determined to be in violation of anti-corruption laws, including the FCPA or other similar laws. Any violation of the FCPA or other applicable anti-corruption laws could result in substantial fines, sanctions, civil and/or criminal penalties and curtailment of operations in certain jurisdictions and might materially adversely affect our business, results of operations or financial condition. In addition, actual or alleged violations could damage our reputation and ability to do business. Further, detecting, investigating, and resolving actual or alleged violations is expensive and can consume significant time and attention of our senior management.

Our operations are subject to various laws and governmental regulations that could restrict our future operations and increase our operating costs.

Many aspects of our operations are subject to various federal, state and local laws and governmental regulations, including laws and regulations governing:

- environmental quality;
- pollution control;
- remediation of contamination;
- preservation of natural resources;
- transportation, and
- worker safety.

Our operations are subject to stringent federal, state and local laws, rules and regulations governing the protection of the environment and human health and safety. Some of those laws, rules and regulations relate to the disposal of hazardous substances, oilfield waste and other waste materials and restrict the types, quantities and concentrations of those substances that can be released into the environment. Several of those laws also require removal and remedial action and other cleanup under certain circumstances, commonly regardless of fault. Our operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, the federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Safe Drinking Water Act, or SDWA, the federal Outer Continental Shelf Lands Act, the Occupational Safety and Health Act, or OSHA, and their state counterparts and similar statutes are the primary statutes that impose the requirements described above and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. The OSHA hazard communication standard, the Environmental Protection Agency "community right-to-know" regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and report information about the hazardous materials we use in our operations to employees, state and local government authorities and local citizens. In addition, CERCLA, also known as the "Superfund" law, and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release or threatened release of hazardous substances into the environment. These persons include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

Environmental laws and regulations are complex and subject to frequent change. Failure to comply with governmental requirements or inadequate cooperation with governmental authorities could subject a responsible party to administrative, civil or criminal action. We may also be exposed to environmental or other liabilities originating from businesses and assets which we acquired from others. Our compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination or regulatory noncompliance may require us to make material expenditures or subject us to liabilities that we currently do not anticipate.

There are a variety of regulatory developments, proposals or requirements and legislative initiatives that have been introduced in the United States and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments are the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol" (an internationally applied protocol, which has been ratified in Colombia, which is a location where we provide drilling services), the Regional Greenhouse Gas Initiative or "RGGI" in the Northeastern United States, and the Western Regional Climate Action Initiative in the Western United States.

The U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases.

In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act. On December 7, 2009, the EPA responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from motor vehicles contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change.

Based on these findings, in 2010 the EPA adopted two sets of regulations that restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of greenhouse gases from motor vehicles and another that requires certain construction and operating permit reviews for greenhouse gas emissions from certain large stationary sources. The stationary source final rule addresses the permitting of greenhouse gas emissions from stationary sources under the Clean Air Act Prevention of Significant Deterioration construction and Title V operating permit programs, pursuant to which these permit programs have been "tailored" to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. In addition, the EPA adopted rules requiring the monitoring and reporting of greenhouse gases from certain sources, including, among others, onshore oil and natural gas production facilities.

In April 2012, the EPA issued regulations specifically applicable to the oil and gas industry that will require operators to significantly reduce volatile organic compounds, or VOC, emissions from natural gas wells that are hydraulically fractured through the use of "green completions" to capture natural gas that would otherwise escape into the air. The EPA also issued regulations that establish standards for VOC emissions from several types of equipment at natural gas well sites, including storage tanks, compressors, dehydrators and pneumatic controllers.

On June 2, 2014, the EPA issued a proposed rule to limit carbon dioxide emissions from existing electric utility generating units. Under the EPA's current proposal, nationwide emissions of carbon dioxide from the power sector would be cut by up to 30% from the 2005 baseline by the year 2030. The required emission reductions would vary state-by-state, and the proposed rule provides each State flexibility in determining how the emission reductions would be achieved.

On January 14, 2015, the EPA announced that it plans to implement additional steps to reduce methane and VOC emissions from the oil and gas industry. Proposed regulations are planned for the summer of 2015 and are expected to address new and modified oil and gas sources, but may also be extended to certain existing sources located in areas not meeting federal standards for ozone.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows. In addition, these developments could curtail the demand for fossil fuels such as oil and gas in areas of the world where our clients operate and thus adversely affect demand for our services, which may in turn adversely affect our future results of operations. Finally, we cannot predict with any certainty whether changes to temperature, storm intensity or precipitation patterns as a result of climate change will have a material impact on our operations.

In addition, our business depends on the demand for land drilling and production services from the oil and gas industry and, therefore, is affected by tax, environmental and other laws relating to the oil and gas industry generally, by changes in those laws and by changes in related administrative regulations. It is possible that these laws and regulations may in the future add significantly to our operating costs or those of our clients, or otherwise directly or indirectly affect our operations.

Our wireline operations involve the use of radioactive isotopes along with other nuclear, electrical, acoustic, and mechanical devices. Our activities involving the use of isotopes are regulated by the U.S. Nuclear Regulatory Commission and specified agencies of certain states. Additionally, we use high explosive charges for perforating casing and formations, and we use various explosive cutters to assist in wellbore cleanout. Such operations are regulated by the U.S. Department of Justice, Bureau of Alcohol, Tobacco, Firearms, and Explosives and require us to obtain licenses or other approvals for the use of densitometers as well as explosive charges. We have obtained these licenses and approvals when necessary and believe that we are in substantial compliance with these federal requirements.

Among the services we provide, we operate as a motor carrier for the transportation of our own equipment and therefore are subject to regulation by the U.S. Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the U.S. Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations.

From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and natural gas wells that may reduce demand for our drilling and well servicing activities and could adversely affect our financial position, results of operations and cash flows.

Hydraulic fracturing is a commonly used process that involves injection of water, sand, and a minor amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. Several proposals are being considered by the EPA and other federal agencies that, if implemented, would impose additional requirements on the practice of hydraulic fracturing. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to concerns regarding potential environmental and physical impacts, including groundwater and drinking water impacts, as well as whether such activities may cause minor earthquakes.

The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act (SDWA) to exclude certain hydraulic fracturing practices from the definition of "underground injection." The EPA has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and has developed draft guidance relating to such practices. In addition, repeal of the SDWA exclusion of hydraulic fracturing has been advocated by certain advocacy organizations and others in the public. Congress has from time to time considered legislation to repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate new regulations and permitting requirements for hydraulic fracturing, and to require the disclosure of the chemical constituents of hydraulic fracturing fluids to a regulatory agency, which would make the information public via the Internet.

Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing. A Progress Report was issued by the EPA in May 2014; peer review of the information provided in the Progress Report is underway. In addition, in April 2012, the EPA issued the first federal air standards for natural gas wells that are hydraulically fractured, which will require operators to significantly reduce VOC emissions through the use of "green completions" to capture natural gas that would otherwise escape into the air. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or "green") completions must be used. The rules also establish specific new requirements, which were effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On September 23, 2013, the EPA published amendments to the rule which would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. On December 19, 2014, the EPA published a final rule clarifying certain aspects of the new rules. On January 14, 2015, the EPA announced that it plans to propose and implement new regulations to further reduce methane and VOC emissions from the oil and gas industry. It is also possible that the EPA will propose additional amendments to its existing oil and gas regulations. These rules may require a number of modifications to our clients' and our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our clients, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

The EPA is also developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by early 2015. The U.S. Department of the Interior has also proposed regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents and has conducted hearings on a possible rule to reduce flaring and venting associated with oil and gas operations on public lands.

In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, that would require, with some exceptions, disclosure of constituents of hydraulic fracturing fluids, or that would impose higher taxes, fees or royalties on natural gas production. Moreover, public debate over hydraulic fracturing and shale gas production continued to see strong public opposition, and has resulted in delays of well permits in some areas.

On June 30, 2014, the State of New York's Court of Appeals upheld the right of individual municipalities in the State of New York to ban hydraulic fracturing using zoning restrictions. In December 2014, New York State Governor Cuomo announced that hydraulic fracturing will be permanently banned in the state. Similarly situated municipalities in other states may seek to ban or restrict resource extraction operations within their borders using zoning restrictions, which could adversely affect the ability of resource extraction enterprises to operate in certain parts of the country, and thus adversely affect demand for our services, which may in turn adversely affect our future results of operations.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our clients. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our drilling and well servicing activities, any or all of which could adversely affect our financial position, results of operations and cash flows.

Our operations are subject to the risk of cyber attacks that could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

Our information technology systems are subject to possible breaches and other threats that could cause us harm. If our systems for protecting against cyber security risks prove not to be sufficient, we could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, or customer data; interruption of business operations; or additional costs to prevent, respond to, or mitigate cyber security attacks. These risks could have a material adverse effect on our business, financial condition and result of operations.

Risks Relating to Our Capitalization and Organizational Documents

We do not intend to pay dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our shareholders.

We have not paid or declared any dividends on our common stock and currently intend to retain any earnings to fund our working capital needs, reduce debt and fund growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and restrictions imposed by the Texas Business Organizations Code and other applicable laws and by our Revolving Credit Facility and Senior Notes. Our debt arrangements include provisions that generally prohibit us from paying dividends on our capital stock, including our common stock.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our articles of incorporation authorize us to issue, without the approval of our shareholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our organizational documents could delay or prevent a change in control of our company even if that change would be beneficial to our shareholders.

The existence of some provisions in our organizational documents could delay or prevent a change in control of our company even if that change would be beneficial to our shareholders. Our articles of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our shareholders to nominate candidates for election as directors or to bring matters for action at annual meetings of our shareholders;
- limitations on the ability of our shareholders to call a special meeting and act by written consent;
- provisions dividing our board of directors into three classes elected for staggered terms; and
- the authorization given to our board of directors to issue and set the terms of preferred stock.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

For a description of our significant properties, see “Business—General” and “Business—Facilities” in Item 1 of this report. We believe that we have sufficient properties to conduct our operations and that our significant properties are suitable for their intended use.

Item 3. 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 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

As of January 29, 2015, 63,867,955 shares of our common stock were outstanding, held by 367 shareholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

Our common stock trades on the New York Stock Exchange under the symbol "PES." The following table sets forth, for each of the periods indicated, the high and low sales prices per share:

	Low	High
Fiscal year ended December 31, 2014		
First Quarter	$ 7.72	$ 12.95
Second Quarter	12.11	17.54
Third Quarter	13.70	18.38
Fourth Quarter	4.22	13.06
Fiscal year ended December 31, 2013		
First Quarter	$ 7.16	$ 9.88
Second Quarter	6.53	8.50
Third Quarter	6.50	7.74
Fourth Quarter	7.05	8.74

The last reported sales price for our common stock on the New York Stock Exchange on January 29, 2015 was $4.10 per share.

We have not paid or declared any dividends on our common stock and currently intend to retain earnings to fund our working capital needs and growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and the restrictions imposed by the Texas Business Organizations Code and other applicable laws and our Revolving Credit Facility and Senior Notes. Our debt arrangements include provisions that generally prohibit us from paying dividends, other than dividends on our preferred stock. We currently have no preferred stock outstanding.

We did not make any unregistered sales of equity securities during the quarter ended December 31, 2014. The following table provides information relating to our repurchase of common shares during the quarter ended December 31, 2014:

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
October 1—October 31	104	$ 12.41	—	—
November 1—November 30	—	$ —	—	—
December 1—December 31	317	$ 5.79	—	—
Total	421	$ 7.43	—	—

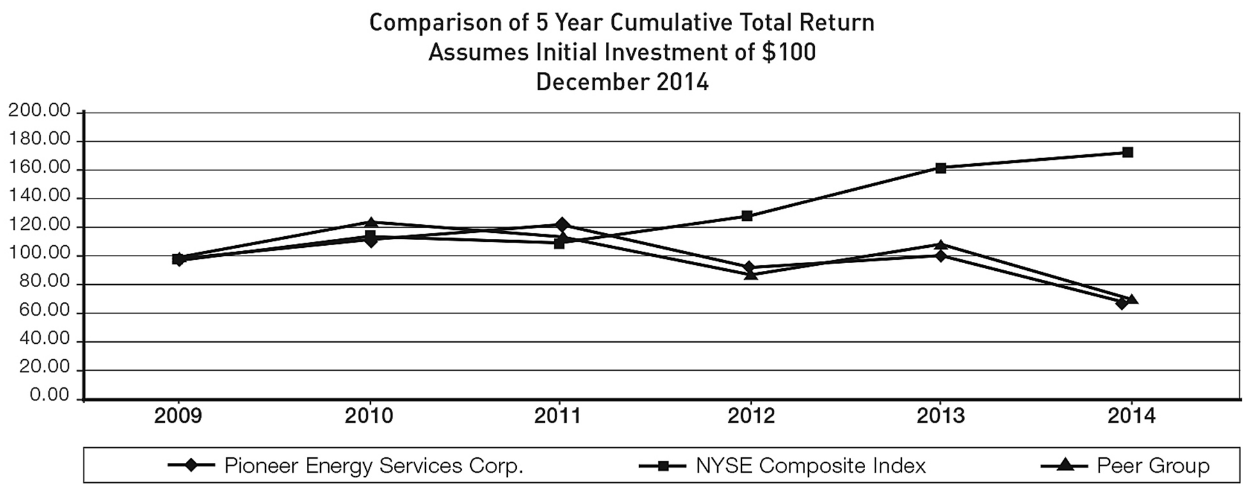
(1) The shares indicated consist of shares of our common stock tendered by employees to the Company during the three months ended December 31, 2014, to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock unit awards, which we repurchased based on the 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.

Performance Graph

The following graph compares, for the periods from December 31, 2009 to December 31, 2014, the cumulative total shareholder return on our common stock with the cumulative total return on the companies that comprise the NYSE Composite Index and a peer group index that includes five companies that provide contract drilling services and/or production services. The companies that comprise the peer group index are Patterson-UTI Energy, Inc., Nabors Industries Ltd., Basic Energy Services, Inc., Precision Drilling Trust and Key Energy Services.

The comparison assumes that $100 was invested on December 31, 2009 in our common stock, the companies that compose the NYSE Composite Index and the peer group index, and further assumes all dividends were reinvested.



Item 6. Selected Financial Data

The following information derives from our audited financial statements. This information should be reviewed in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report and the financial statements and related notes this report contains.

	Year ended December 31,				
	2014 (1)	2013 (2)	2012	2011	2010
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Revenues	$1,055,223	$ 960,186	$ 919,443	$ 715,941	$ 487,210
Income (loss) from operations	23,984	(6,229)	81,811	57,458	(18,572)
Income (loss) before income taxes	(49,322)	(55,778)	46,386	20,833	(47,558)
Net earnings (loss) applicable to common stockholders	(38,018)	(35,932)	30,032	11,177	(33,261)
Earnings (loss) per common share-basic	$ (0.60)	$ (0.58)	$ 0.49	$ 0.19	$ (0.62)
Earnings (loss) per common share-diluted	$ (0.60)	$ (0.58)	$ 0.48	$ 0.19	$ (0.62)
Other Financial Data:					
Net cash provided by operating activities	$ 233,041	$ 174,580	$ 199,366	$ 144,879	$ 98,351
Net cash used in investing activities	(151,918)	(150,676)	(361,231)	(307,484)	(129,481)
Net cash provided by (used in) financing activities	(73,584)	(20,252)	99,401	226,791	12,762
Capital expenditures	$ 188,121	125,420	379,272	237,787	135,151

	As of December 31,				
	2014	2013	2012	2011	2010
	(In thousands)				
Balance Sheet Data:					
Working capital	$ 121,882	$ 118,547	$ 62,236	$ 129,932	$ 76,142
Property and equipment, net	856,541	937,657	1,014,340	793,956	655,508
Long-term debt and capital lease obligations, excluding current installments	455,053	499,666	518,725	418,728	279,530
Shareholders' equity	495,064	518,433	547,680	510,445	396,333
Total assets	1,171,589	1,229,623	1,339,776	1,172,754	841,343

(1) The statement of operations and other financial data for the year ended December 31, 2014 reflect the impact of impairment charges on our property and equipment of $73.0 million.

(2) The statement of operations and other financial data for the year ended December 31, 2013 reflect the impact of a goodwill impairment charge of $41.7 million and an intangible asset impairment charge of $3.1 million.

Item 7. 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, including under the headings "Special Note Regarding Forward-Looking Statements" in the Introductory Note to Part I and "Risk Factors" in Item 1A. These factors are not necessarily all the important factors that could affect us. Unpredictable or unknown factors we have not discussed in this report could also have material adverse effects on actual results of matters that are the subject of our forward-looking statements. All forward-looking statements speak only as of the date on which they are made and we undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise. We advise our shareholders that they should (1) be aware that important factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements.

Company Overview

Pioneer Energy Services Corp. (formerly called "Pioneer Drilling Company") was incorporated under the laws of the State of Texas in 1979 as the successor to a business that had been operating since 1968. Since September 1999, we have significantly expanded our drilling rig fleet through acquisitions and through the construction of rigs from new and used components. In March 2008, we acquired two production services companies which significantly expanded our service offerings to include well servicing and wireline services. Through these purchases, we also acquired fishing and rental services operations, which were subsequently sold on September 17, 2014. We also acquired a coiled tubing services business at the end of 2011, to expand our existing production services offerings. We have continued to invest in the growth of all our core service offerings through acquisitions and organic growth.

Pioneer Energy Services Corp. provides drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies throughout much of the onshore oil and gas producing regions of the United States and internationally in Colombia. We also provide coiled tubing and wireline services offshore in the Gulf of Mexico. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of a well site and enable us to meet multiple needs of our clients.

Business Segments

We currently conduct our operations through two operating segments: our Drilling Services Segment and our Production Services Segment. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 11, *Segment Information*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

- *Drilling Services Segment*—Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies through our six drilling divisions in the US and internationally in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on either a daywork or turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed.

  Since October 2014, domestic and international oil prices have declined significantly to historically low price levels resulting in a downturn in our industry. As a result, we performed an impairment evaluation of all our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*, which resulted in $71.0 million of impairment charges to reduce the carrying value of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value.

  As of December 31, 2014, we owned a total of 31 mechanical and lower horsepower electric drilling rigs, which includes the nine rigs that were idle and classified as held for sale as of year-end and 15 rigs that we expect to place as held for sale during the first quarter of 2015, after their current contracts are completed. In January and February 2015, we sold six of these drilling rigs.

  The following is a summary of our drilling rig counts as of December 31, 2014 and February 1, 2015, as well as our expected count at March 31, 2015.

	Drilling Rigs Owned	Drilling Rigs Held for Sale	Drilling Rig Fleet Count
As of December 31, 2014	62	(9)	53
As of February 1, 2015	59	(12)	47
Expected at March 31, 2015	56	(18)	38

  As of February 1, 2015, the drilling rigs in our fleet are assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
West Texas	10
North Dakota	9
Utah	4
Appalachia	3
Colombia	8
	47

  We are currently constructing five new-build 1,500 horsepower AC drilling rigs which we expect to deliver and begin operating under long-term drilling contracts in 2015, with the first two rigs to be deployed during the second quarter, two rigs in the third quarter, and the final rig by the end of the year. Excluding the rigs which we expect to sell in the near-term and considering the five new-build drilling rigs under construction, we expect to end 2015 with a drilling fleet of 43 rigs.

  As of February 1, 2015, 40 of our 47 drilling rigs are earning revenues under drilling contracts, 29 of which are earning under term contracts. Four of our drilling rigs in Colombia are currently working under term contracts that extend through mid-2015 and we are actively marketing our other four rigs to multiple clients to diversify our client base in Colombia.

In response to the dramatic decline in oil prices during recent months, we have received early termination notices for 12 of our 29 drilling rigs that are earning revenues under term contracts. These 12 drilling rigs will be released upon completion of their current wells, all of which are expected to be completed by the end of the first quarter 2015, resulting in approximately $43.5 million of early termination payments which will be recognized as revenue over the remaining term of the contracts, $0.3 million of which was recognized in 2014.

- *Production Services Segment*—Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. On September 17, 2014, we completed the sale of our fishing and rental services operations. We provide our services to a diverse group of oil and gas exploration and production companies. The primary production services we offer are the following:

  - Well Servicing. A range of services are required in order to establish production in newly-drilled wells and to maintain production over the useful lives of active wells. We use our well servicing rig fleet to provide these necessary services, including the completion of newly-drilled wells, maintenance and workover of active wells, and plugging and abandonment of wells at the end of their useful lives. As of February 1, 2015, we operate 107 rigs with 550 horsepower and 10 rigs with 600 horsepower through 11 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota.

  - Wireline Services. In order for oil and gas exploration and production companies to better understand the reservoirs they are drilling or producing, they require logging services to accurately characterize reservoir rocks and fluids. To complete a well, the production casing must be perforated to establish a flow path between the reservoir and the wellbore. We use our fleet of wireline units to provide these important logging and perforating services. We provide both open and cased-hole logging services, including the latest pulsed-neutron technology. In addition, we provide services which allow oil and gas exploration and production companies to evaluate the integrity of wellbore casing, recover pipe, or install bridge plugs. As of December 31, 2014, we have four wireline units placed as held for sale, for which we recognized approximately $0.3 million of impairment charges to reduce their carrying values to fair value. As of February 1, 2015, we operate a fleet of 128 wireline units through 24 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 February 1, 2015, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are currently deployed through three locations in Texas and Louisiana.

Pioneer Energy Services' corporate office is located at 1250 NE Loop 410, Suite 1000, San Antonio, Texas 78209. Our phone number is (855) 884-0575 and our website address is www.pioneeres.com. We make available free of charge through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission (SEC). Information on our website is not incorporated into this report or otherwise made part of this report.

Market Conditions in Our Industry

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

In recent years, generally increasing oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. Even though advancements in technology have improved the efficiency of drilling rigs, demand remained steady, particularly for drilling rigs that are able to drill horizontally. Beginning in October 2014, domestic and international oil prices have significantly declined to historically low price levels. If oil prices continue to decline, or if oil and natural gas prices remain at current levels for an extended period of time, then industry equipment utilization and revenue rates will further decrease, both domestically and in Colombia.

While drilling and production services have historically trended similarly in response to fluctuations in commodity prices, 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 expenditures to sustain production. We expect an increase in pricing pressure and a highly competitive production services environment in 2015, but we believe our high-quality equipment and services are well positioned to compete.

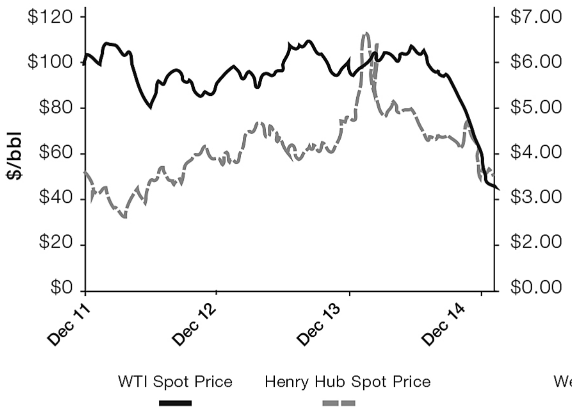
Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or operating expenditure.

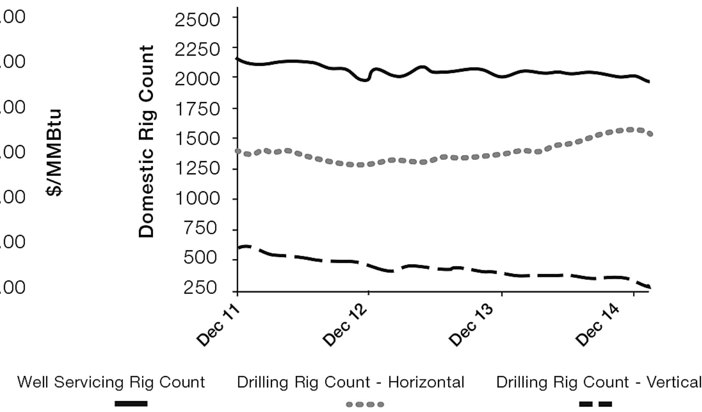
Capital expenditures by oil and gas exploration and production companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of years. As such, capital expenditure economics often require the use of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

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

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





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

Colombian oil prices have historically trended in line with West Texas Intermediate (WTI) oil prices. However, fluctuations in oil prices have a less significant impact on demand for drilling and production services in Colombia as compared to the impact on demand in North America. Demand for drilling and production services in Colombia is largely dependent upon its national oil company's long-term exploration and production programs.

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

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 this Annual Report on Form 10-K.

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 $34.9 million as of December 31, 2014), 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 2012, we filed a registration statement that permits us to sell equity or debt in one or more offerings up to a total dollar amount of $300 million. As of February 1, 2015, the entire $300 million under the shelf registration statement is available for equity or debt offerings. In the future, we may consider equity and/or debt offerings, as appropriate, to meet our liquidity needs.

In March 2010, we issued $250 million of senior notes with a coupon interest rate of 9.875% that were set to mature in 2018 (the "2010 Senior Notes"), the net proceeds from which were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility. In November 2011, we issued an additional $175 million of senior notes (the "2011 Senior Notes") with the same terms and conditions as the 2010 Senior Notes. We received $172.7 million of net proceeds from the issuance of the 2011 Senior Notes, a portion of which were used to fund the acquisition of our coiled tubing business in December 2011. In March 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the "2014 Senior Notes"), the net proceeds from which, combined with cash on hand, were used to fund the repayment of $300 million of aggregate principal amount of 2010 and 2011 Senior Notes in March and May 2014. In October 2014, we redeemed the remaining $125.0 million in aggregate principal amount of the 2010 and 2011 Senior Notes, primarily funded by proceeds from our revolving credit facility and through cash on hand.

Our Revolving Credit Facility, as amended on September 22, 2014, provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of $350 million, all of which matures in September 2019. In addition, at our request, and with the lenders' consent, the aggregate commitments of the lenders under the Revolving Credit Facility may be increased up to an additional $100 million provided that no default exists, all representations and warranties are true and correct, and compliance with financial covenants as set forth in the Revolving Credit Facility is met immediately prior to and after giving effect thereto. As of February 1, 2015, we had $150 million outstanding under our Revolving Credit Facility and $18.5 million in committed letters of credit, which resulted in borrowing availability of $181.5 million under our Revolving Credit Facility. There are no limitations on our ability to access this borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. Additional information regarding these covenants is provided in the *Debt Requirements* section below. Borrowings under the Revolving Credit Facility are available for selective acquisitions, working capital and other general corporate purposes.

We currently expect that cash and cash equivalents, cash generated from operations, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and available borrowings under our Revolving Credit Facility are adequate to cover our liquidity requirements for at least the next 12 months.

Uses of Capital Resources

For the years ended December 31, 2014 and 2013, our primary uses of capital resources were for property and equipment additions which consisted of the following (amounts in thousands):

	Year ended December 31,	
	2014	**2013**
Drilling Services Segment:		
Routine	$ 43,403	$ 39,276
Discretionary	24,340	35,569
Fleet additions	34,618	41,679
Total Drilling Services Segment	102,361	116,524
Production Services Segment:		
Routine	22,927	23,053
Discretionary	21,854	20,092
Fleet additions	28,236	5,687
Total Production Services Segment	73,017	48,832
Net cash used for purchases of property and equipment	175,378	165,356
Net impact of accruals	12,743	(39,936)
Total Capital Expenditures	$ 188,121	$ 125,420

Our Drilling Services Segment incurred $37.8 million and $12.3 million of costs, including accruals for capital expenditures, on the construction of our new-build drilling rigs during the years ended December 31, 2014 and 2013, respectively. Additionally, during the year ended December 31, 2014, we performed significant upgrade projects to various rigs in our drilling fleet including, among others, the installation of five additional walking systems, three additional automatic catwalks and one additional top drive, the upgrade of one drilling rig to higher horsepower, and we upgraded four rigs with higher horsepower mud pumps. During the year ended December 31, 2013, we performed significant upgrade projects to various rigs in our drilling fleet including, among others, the installation of four additional automatic catwalks and two additional walking systems, the upgrade of two drilling rigs to higher horsepower and we upgraded four rigs with higher horsepower mud pumps. In connection with drilling equipment upgrades and the construction of new-build drilling rigs, we capitalized $0.7 million and $0.9 million of interest costs during the years ended December 31, 2014 and 2013, respectively.

Our Production Services Segment acquired six wireline units, seven well servicing rigs and four coiled tubing units during the year ended December 31, 2014. During the year ended December 31, 2013, we acquired three wireline units and one well servicing rig.

Currently, we expect to spend approximately $165 million to $180 million on capital expenditures during 2015. We expect the total capital expenditures for 2015 will be allocated approximately 70% for our Drilling Services Segment and approximately 30% for our Production Services Segment. Our planned capital expenditures for the year ending December 31, 2015 include the remaining payments for five new-build drilling rigs, nine well servicing rigs, eight wireline units, routine capital expenditures and certain drilling equipment which was ordered in 2014 but requires long lead-time orders. Actual capital expenditures may vary depending on the timing of commitments and payments, as well as the level of new-build and other expansion opportunities that meet our strategic and return on capital employed criteria. We expect to fund capital expenditures in 2015 from operating cash flow in excess of our working capital requirements, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and from borrowings under our Revolving Credit Facility, if necessary.

Working Capital

Our working capital was $121.9 million at December 31, 2014, compared to $118.5 million at December 31, 2013. Our current ratio, which we calculate by dividing current assets by current liabilities, was 1.8 at December 31, 2014 compared to 2.0 at December 31, 2013.

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

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

	December 31, 2014	December 31, 2013	Change
Cash and cash equivalents	$ 34,924	$ 27,385	$ 7,539
Receivables:			
Trade, net of allowance for doubtful accounts	136,161	115,908	20,253
Unbilled receivables	38,002	49,535	(11,533)
Insurance recoveries	10,900	8,607	2,293
Income taxes and other	5,138	2,310	2,828
Deferred income taxes	10,998	13,092	(2,094)
Inventory	14,117	13,232	885
Assets held for sale	9,909	—	9,909
Prepaid expenses and other current assets	8,925	9,311	(386)
Current assets	269,074	239,380	29,694
Accounts payable	64,305	43,718	20,587
Current portion of long-term debt	27	2,847	(2,820)
Deferred revenues	3,315	699	2,616
Accrued expenses:			
Payroll and related employee costs	40,058	30,020	10,038
Insurance premiums and deductibles	12,829	10,940	1,889
Insurance claims and settlements	10,900	8,607	2,293
Interest	5,432	12,275	(6,843)
Other	10,326	11,727	(1,401)
Current liabilities	147,192	120,833	26,359
Working capital	$ 121,882	$ 118,547	$ 3,335

The increase in cash and cash equivalents during the year ended December 31, 2014 is primarily due to $233.0 million of cash provided by operating activities, $15.1 million of proceeds from the sale of our fishing and rental services operations and $8.4 million of proceeds from the sale of assets, partially offset by $175.4 million used for purchases of property and equipment and $73.6 million of cash used in our financing activities.

The net increase in our total trade and unbilled receivables as of December 31, 2014 as compared to December 31, 2013 is primarily the result of the increase in consolidated revenues of $44.9 million, or 19%, for the quarter ended December 31, 2014 as compared to the quarter ended December 31, 2013, and due to the timing of the billing and collection cycles for long-term drilling contracts in Colombia.

The increase in both our insurance recoveries receivables and our insurance claims and settlements accrued expenses as of December 31, 2014 as compared to December 31, 2013 is primarily due to an increase in our insurance company's reserve for workers' compensation claims in excess of our deductibles.

The increase in income taxes and other receivables as of December 31, 2014 as compared to December 31, 2013 is primarily due to the movement of $1.5 million in prepaid taxes associated with our Colombian operations from noncurrent to current receivables, as we expect to utilize them in the near term, as well as a $1.4 million receivable from the settlement of litigation in our favor.

The current portion of our long-term debt as of December 31, 2013 was primarily related to short-term financing for insurance premiums which were repaid in 2014.

The increase in accounts payable as of December 31, 2014 as compared to December 31, 2013 is due to an increase in our accruals for capital expenditures as of December 31, 2014 as compared to December 31, 2013, and due to the 18% increase in our operating costs for the quarter ended December 31, 2014 as compared to the quarter ended December 31, 2013.

The increase in deferred revenues as of December 31, 2014 as compared to December 31, 2013 is primarily related to prepayments made related to ongoing drilling contracts and the deferral of early termination fees on one term contract.

As of December 31, 2014, our consolidated balance sheet reflects assets held for sale of $9.9 million, which represents the fair value of nine drilling rigs, four wireline units, two real estate properties and other drilling equipment.

The increase in accrued payroll and employee related costs as of December 31, 2014 as compared to December 31, 2013 is primarily due to higher accruals for our 2014 annual bonuses at above target achievement levels, as compared to 2013 bonuses which were earned at an amount below the target level, as well as an increase due to timing of pay periods.

The increase in insurance premiums and deductibles as of December 31, 2014 as compared to December 31, 2013 is primarily due to an increase in our accrual for workers compensation insurance costs resulting from an increase in our estimated liability for the deductibles under these policies.

The decrease in accrued interest expense as of December 31, 2014 as compared to December 31, 2013 is primarily due to the repayment of $425 million of our 2010 and 2011 Senior Notes in 2014 with proceeds from our Revolving Credit Facility and our 2014 Senior Notes which incur interest at a lower rate.

The decrease in other accrued expenses as of December 31, 2014 as compared to December 31, 2013 is primarily due to a decrease in the Colombian equity tax obligation and a decrease in property taxes due to the timing of payments, partially offset by an increase in our sales tax accrual.

Long-term Debt and Other Contractual Obligations

The following table includes information about the amount and timing of our contractual obligations at December 31, 2014 (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	$ 455,080	$ 27	$ 53	$ 155,000	$ 300,000
Interest on debt	155,553	22,130	44,254	43,231	45,938
Purchase commitments	114,717	90,846	23,871	—	—
Operating leases	14,934	4,441	5,991	2,993	1,509
Incentive compensation and severance	13,701	7,757	5,944	—	—
Total	$ 753,985	$ 125,201	$ 80,113	$ 201,224	$ 347,447

At December 31, 2014, debt obligations consist of $300 million of principal amount outstanding under our Senior Notes, $155.0 million outstanding under our Revolving Credit Facility and $0.1 million of other debt outstanding. The $155.0 million outstanding under our Revolving Credit Facility is due at maturity on September 22, 2019. However, we may make principal payments to reduce the outstanding balance prior to maturity when cash and working capital is sufficient. The $300 million principal amount outstanding under our 2014 Senior Notes will mature on March 15, 2022.

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 2.4% interest rate that was in effect at December 31, 2014, and (2) the outstanding balance of $155.0 million at December 31, 2014 to be paid at maturity on September 22, 2019. Interest payment obligations on our 2014 Senior Notes are calculated based on the coupon interest rate of 6.125% due semi-annually in arrears on March 15 and September 15 of each year.

Purchase commitments primarily relate to components ordered for our new-build drilling rigs, purchases of other new equipment and equipment upgrades. The total estimated cost, excluding capitalized interest, for the five new-build drilling rigs is approximately $125 million, of which $37.2 million has already been incurred, and $59.7 million of which is reflected in the purchase commitments table above. In addition, $42.7 million of the purchase commitments in the table above represent obligations for well servicing rigs and other drilling equipment that were ordered during 2014, but which require long lead-time orders.

Operating leases consist of lease agreements for office space, operating facilities, equipment and personal property.

Incentive compensation is payable to our employees, generally contingent upon their continued employment through the date of each respective award's payout.

Debt Requirements

The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and letter of credit exposure. There are no limitations on our ability to access the $350 million borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. At December 31, 2014, we were in compliance with our financial covenants under the Revolving Credit Facility. Our total consolidated leverage ratio was 1.8 to 1.0, our senior consolidated leverage ratio was 0.7 to 1.0, and our interest coverage ratio was 6.7 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

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

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

At December 31, 2014, our senior consolidated leverage ratio was not greater than 2.00 to 1.00 and therefore, we were not subject to the capital expenditure threshold restrictions listed above.

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

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

In addition to the financial covenants under our Revolving Credit Facility, the Indenture governing our Senior Notes both contain certain restrictions generally on 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 December 31, 2014, 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—Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

The following table provides information about our operations for the years ended December 31, 2014 and 2013 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Year ended December 31, 2014	Year ended December 31, 2013
Drilling Services Segment:		
Revenues	$ 516,473	$ 528,327
Operating costs	345,862	351,630
Drilling Services Segment margin	$ 170,611	$ 176,697
Average number of drilling rigs	62.0	68.2
Utilization rate	87%	84%
Revenue days	19,602	20,977
Average revenues per day	$ 26,348	$ 25,186
Average operating costs per day	17,644	16,763
Drilling Services Segment margin per day	$ 8,704	$ 8,423
Production Services Segment:		
Revenues	$ 538,750	$ 431,859
Operating costs	340,102	277,625
Production Services Segment margin	$ 198,648	$ 154,234
Combined:		
Revenues	$ 1,055,223	$ 960,186
Operating costs	685,964	629,255
Combined margin	$ 369,259	$ 330,931
Adjusted EBITDA	$ 277,081	$ 234,742

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'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 income (expense), taxes, depreciation, amortization, loss on extinguishment of debt and impairments. We use this non-GAAP measure, together with our GAAP financial metrics, to assess our financial performance and evaluate our overall progress towards meeting our long-term financial objectives. We believe that this measure is useful to investors and analysts in allowing for greater transparency of our operating performance and makes it easier to compare our results with those of other companies within our industry. Adjusted EBITDA should not be considered (a) in isolation of, or as a substitute for, net income (loss), (b) as an indication of cash flows from operating activities or (c) as a measure of liquidity. In addition, Adjusted EBITDA does not represent funds available for discretionary use. Adjusted EBITDA may not be comparable to other similarly titled measures reported by other companies.

A reconciliation of combined Drilling Services Segment margin and Production Services Segment margin to net income (loss), as reported, and a reconciliation of Adjusted EBITDA to net income (loss), as reported, are set forth in the following table.

	Year ended December 31,	
	2014	2013
	(amounts in thousands)	
Reconciliation of combined margin and Adjusted EBITDA to net loss:		
Combined margin	$ 369,259	$ 330,931
General and administrative	(103,385)	(94,183)
Bad debt expense	(1,445)	(767)
Gain on sale of fishing and rental services operations	10,702	—
Gain on settlement of litigation	5,254	—
Other expense	(3,304)	(1,239)
Adjusted EBITDA	277,081	234,742
Depreciation and amortization	(183,376)	(187,918)
Impairment charges	(73,025)	(54,292)
Interest expense	(38,781)	(48,310)
Loss on extinguishment of debt	(31,221)	—
Income tax benefit	11,304	19,846
Net loss	$ (38,018)	$ (35,932)

Our Drilling Services Segment's revenues decreased by $11.9 million, or 2%, during 2014 as compared to 2013, resulting primarily from a decrease in revenue days of 7%, partially offset by an increase in revenues per day of 5%, or $1,162 per day. Our Drilling Services Segment's operating costs decreased by $5.8 million, or 2%, during 2014 as compared to 2013, primarily resulting from a decrease in revenue days, partially offset by higher operating costs per day which increased by 5%, or $881 per day. Revenue days decreased primarily due to the sale of eight drilling rigs in October 2013, some of which had been earning a standby dayrate during 2013, and due to lower utilization in Colombia where we experienced downtime primarily due to client delays in preparing well sites during the first half of 2014. Overall decreases in revenues and operating costs were partially offset by an increase in domestic revenues and operating costs per day during 2014.

Our average revenues per day increased by 5% or $1,162 per day, while our average operating costs per day increased by 5% or $881 per day, during 2014, as compared to 2013. Our average revenues and operating costs per day increased primarily due to increased turnkey work performed during 2014 as well as higher labor costs during 2014 which are reimbursed by the client, resulting in higher average revenues and operating costs per day.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain. As demand for drilling rigs decreases, daywork rates move down and we may switch to performing more turnkey drilling contracts to maintain higher utilization rates and to improve our Drilling Services Segment's margins. Turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts. During the years ended December 31, 2014 and 2013, we completed 106 and 27 turnkey contracts, respectively, representing 6% and 3% of our total drilling revenues for each year, respectively. During 2014, we experienced an increase in demand for turnkey programs using lower horsepower rigs to drill a series of surface holes on pad sites.

Our Production Services Segment's revenues increased by $106.9 million, or 25%, during 2014, as compared to 2013, while operating costs increased by $62.5 million, or 23%. The increases in our Production Services Segment's revenues and operating costs are primarily a result of the increased demand for our services. The number of wireline jobs we completed increased by 3% during 2014, as compared to 2013. The total rig hours for our well servicing fleet increased by 12%, during 2014, as compared to 2013. Our coiled tubing utilization increased to 51% during 2014 from 47% during 2013. Increased pricing for these services also contributed to the increase in revenues, which was primarily due to a greater mix of higher priced jobs performed in our wireline and coiled tubing businesses. The greater mix of higher cost wireline and coiled tubing jobs performed also resulted in the increase in operating costs during 2014, as compared to 2013.

Our general and administrative expense increased by approximately $9.2 million, or 10%, during 2014, as compared to 2013, primarily due to an increase in payroll and compensation related expenses as we are projecting higher incentive compensation based on our company's performance, as well as $1.9 million of severance costs.

In September 2014, we sold our fishing and rental services operations for total consideration of $16.1 million, resulting in a net pretax gain of $10.7 million.

We recorded gains of $5.3 million related to settlements of litigation in our favor related to non-compete agreements during the year ended December 31, 2014.

Our other expense of $3.3 million for 2014 is primarily related to net foreign currency loss recognized for our Colombian operations due to the rise in the value of the U.S. dollar relative to the Colombian peso.

Our depreciation and amortization expenses decreased by $4.5 million during 2014 as compared to 2013, primarily as a result of the sales of equipment during 2013, as well as the impairment charge to write down coiled tubing intangible assets to fair value as of June 30, 2013.

During the year ended December 31, 2014, we recorded $71.0 million of impairment charges to reduce the carrying values of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value. This impairment charge is not expected to have an impact on our liquidity or debt covenants; however, it is a reflection of the overall downturn in our industry, drop in oil prices in the fourth quarter of 2014 and decline in our projected future cash flows. Additionally, we recorded $2.0 million of impairment charges during the year ended December 31, 2014 to reduce the carrying values of certain other assets, which were placed as held for sale during the year, to their estimated fair values, based on expected sales price.

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

Our interest expense decreased by $9.5 million during 2014, as compared to 2013, primarily due to the repayment of 2010 and 2011 Senior Notes which incurred interest at a higher rate than the 2014 Senior Notes which we issued in March 2014.

Our loss on debt extinguishment during the year ended December 31, 2014 represents the tender and redemption premiums and the write-off of net unamortized debt discount and debt issuance costs associated with the 2010 and 2011 Senior Notes that were redeemed in 2014.

Our effective income tax rate for the year ended December 31, 2014 was 23%, which is lower than the federal statutory rate in the United States, primarily due to the effect of foreign currency translation, other permanent differences, valuation allowance and the impact of state income taxes. Items such as non-deductible expenses and state income taxes had a reverse effect on the income tax rate due to the negative pre-tax earnings.

Statements of Operations Analysis—Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

The following table provides information about our operations for the years ended December 31, 2013 and 2012 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Year ended December 31, 2013	Year ended December 31, 2012
Drilling Services Segment:		
Revenues	$ 528,327	$ 498,867
Operating costs	351,630	333,846
Drilling Services Segment margin	$ 176,697	$ 165,021
Average number of drilling rigs	68.2	65.0
Utilization rate	84%	87%
Revenue days	20,977	20,728
Average revenues per day	$ 25,186	$ 24,067
Average operating costs per day	16,763	16,106
Drilling Services Segment margin per day	$ 8,423	$ 7,961
Production Services Segment:		
Revenues	$ 431,859	$ 420,576
Operating costs	277,625	252,775
Production Services Segment margin	$ 154,234	$ 167,801
Combined:		
Revenues	$ 960,186	$ 919,443
Operating costs	629,255	586,621
Combined margin	$ 330,931	$ 332,822
Adjusted EBITDA	$ 234,742	$ 249,283

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.

	Year ended December 31, 2013	Year ended December 31, 2012
	(amounts in thousands)	
Reconciliation of combined margin and Adjusted EBITDA to net income (loss):		
Combined margin	$ 330,931	$ 332,822
General and administrative	(94,183)	(85,603)
Bad debt (expense) recovery	(767)	440
Other (expense) income	(1,239)	1,624
Adjusted EBITDA	234,742	249,283
Depreciation and amortization	(187,918)	(164,717)
Impairment charges	(54,292)	(1,131)
Interest expense	(48,310)	(37,049)
Income tax benefit (expense)	19,846	(16,354)
Net income (loss)	$ (35,932)	$ 30,032

Our Drilling Services Segment's revenues increased by $29.5 million, or 6%, during 2013 as compared to 2012, resulting primarily from an increase in revenues per day of 5%, or $1,119 per day, as well as an increase in revenue days of 1%. Our Drilling Services Segment's operating costs increased by $17.8 million, or 5%, during 2013 as compared to 2012, primarily resulting from higher operating costs per day which increased by 4%, or $657 per day, and partially due to an increase in revenue days.

The increases in our Drilling Services Segment's revenues and operating costs per day were primarily due to increased utilization in Colombia, where our revenues and costs per day are higher than our domestic drilling rigs, as well as the deployment of all our new-build drilling rigs into areas of the U.S. which experience higher revenues and costs per day, due to higher demand. We deployed seven of our new-build drilling rigs during the second half of 2012, with the remaining three in the first quarter of 2013. The overall increases in revenues and operating costs were partially offset by a slight decrease in utilization for our domestic drilling rigs, despite an increase in revenue days attributable to the operations of our new-build drilling rigs during 2013.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain. As demand for drilling rigs decreases, daywork rates move down and we may switch to performing more turnkey drilling contracts to maintain higher utilization rates and to improve our Drilling Services Segment's margins. Turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts. During the years ended December 31, 2013 and 2012, we completed 27 and 11 turnkey contracts, respectively, representing 3% and 3% of our total drilling revenues for each year, respectively.

Our Production Services Segment's revenues increased by $11.3 million, or 3%, during 2013, as compared to 2012, while operating costs increased by $24.9 million, or 10%.

The increase in our Production Services Segment's revenues is primarily due to increased rig hours and pricing in our well servicing operations due to higher demand for these services during 2013, as compared to 2012, while the overall increase was partially offset by a decrease in revenues from our coiled tubing operations. The total rig hours of our well servicing fleet increased by 7% for the year ended December 31, 2013, partly due to expansion of our fleet during 2012 and 2013, while pricing increased by approximately 4%, as compared to 2012. Revenues from our coiled tubing operations decreased as a result of increased competition in the coiled tubing market and our utilization decreased from 59% in 2012 to 47% in 2013.

The increase in our Production Services Segment's operating costs is primarily due to an increase in our operating costs for our wireline operations which incurred higher average costs per job during 2013, as compared to 2012, as well as an increase in costs for our well servicing operations which experienced higher demand during 2013, as compared to 2012. The number of wireline jobs we completed during 2013 was only 1% higher than the number we completed in 2012, while our average cost per job increased by approximately 11%. The increase in our average cost per wireline job during 2013 was primarily due to a greater mix of higher cost jobs performed during the year, as compared to 2012. We also experienced some increase in labor costs in our Production Services Segment during 2013.

Our general and administrative expense increased by approximately $8.6 million, or 10% during 2013, as compared to 2012, primarily due to the overall expansion of our business in recent years. During 2012, we expanded our well servicing and wireline fleets by approximately 21% and 14%, respectively, and deployed ten new-build drilling rigs during late 2012 and early 2013. The overall expansion of our business increased our general and administrative expense for the year ended December 31, 2013, as compared to 2012, including an increase of $7.0 million in payroll and compensation related expenses primarily resulting from the additional cost of personnel which we have hired over the recent years to support our growth.

Our bad debt recovery for the year ended December 31, 2012 related to the collection of $0.5 million for an account receivable which had been written off prior to 2011.

Our other expense of $1.2 million and other income of $1.6 million for the years ended December 31, 2013 and 2012, respectively, is primarily related to foreign currency exchange gains and losses recognized for our Colombian operations.

Our depreciation and amortization expenses increased by $23.2 million during 2013 as compared to 2012, as a result of our expansion in both our drilling and production services segments. The addition of our new-build drilling rigs that went into service in late 2012 and early 2013 resulted in an increase of approximately $12.1 million during the year ended December 31, 2013, as compared to 2012, while the remaining increase is primarily due to the expansion of our well servicing, wireline and coiled tubing fleets in 2012 and 2013.

We recorded impairment charges on our property and equipment of $9.5 million for the year ended December 31, 2013 in association with our decision to place eight of our mechanical drilling rigs and other production services equipment as held for sale. During the year ended December 31, 2012, we recorded impairment charges on our property and equipment of $1.1 million in association with our decision to retire two mechanical drilling rigs, with most of their components to be used as spare parts, as well as two wireline units and other wireline equipment.

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

Our interest expense increased by $11.3 million for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily due to less capitalized interest during the year ended December 31, 2013, as compared to 2012, associated with the capital expenditures for our new-build drilling rigs and for upgrades to our drilling rig fleet.

Our effective income tax rate for the year ended December 31, 2013 was 36%, which is slightly higher than the federal statutory rate in the United States, due to the impact of state income taxes, and partially offset by the effect of foreign translation, the impact of lower effective tax rates in foreign jurisdictions and other permanent differences.

Inflation

Wage rates for our operations personnel are impacted by inflationary pressures when the demand for drilling and production services increases and the availability of personnel is scarce. With the increase in demand from 2010 through 2011 and the resulting tightening of labor markets, we had a wage rate increase of approximately 10% across multiple drilling divisions in January 2012. We experienced modest wage rate increases in our Production Services Segment during 2013 and 2014.

Costs for equipment repairs and maintenance, upgrades and new equipment construction are also impacted by inflationary pressures when the demand for drilling services increases. We estimate that we experienced an increase in these costs of approximately 5% to 10% during 2012 and 2013 and a more moderate increase during 2014.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Revenue and Cost Recognition—Our Drilling Services Segment earns revenues by drilling oil and gas wells for our clients under daywork or turnkey contracts, which usually provide for the drilling of a single well. Drilling contracts for individual wells are usually completed in less than 60 days. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. All of our revenues are recognized net of applicable sales taxes.

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

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

The risks to us under a turnkey contract are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors' services, supplies, cost escalations and personnel operations.

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

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

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

Our Production Services Segment earns revenues for well servicing, wireline services and coiled tubing services pursuant to master services agreements based on purchase orders, contracts or other arrangements with the client that include fixed or determinable prices. Production services jobs are generally short-term and are charged at current market rates. Production service revenue is recognized when the service has been rendered and collectability is reasonably assured.

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

Since October 2014, domestic and international oil prices have declined significantly to historically low price levels resulting in a downturn in our industry. As a result, we performed an impairment evaluation of all our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*, which resulted in $71.0 million of impairment charges to reduce the carrying value of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value. Additionally, we recorded $2.0 million of impairment charges during the year ended December 31, 2014 to reduce the carrying values of certain other assets, which were placed as held for sale during the year, to their estimated fair values, based on expected sales price.

As of December 31, 2014, we owned a total of 31 mechanical and lower horsepower electric drilling rigs, which includes the nine rigs that were idle and classified as held for sale as of year-end and 15 rigs that we expect to place as held for sale during the first quarter of 2015, after their current contracts are completed. With the significant decline in oil prices over the recent months, we performed impairment testing on all the mechanical and lower horsepower drilling rigs in our fleet. In order to estimate our future undiscounted cash flows from the use and eventual disposition of these assets, we incorporated probabilities of selling these rigs in the near term, versus working them at a significantly reduced expected rate of utilization through the end of their remaining useful lives. Our testing indicated that the carrying value of these assets was more than our estimated undiscounted cash flows, resulting in a total impairment of $71.0 million to reduce the carrying value of these assets to their estimated fair value of $34.0 million, which was based on market appraisals, which are considered Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures.* This impairment charge is not expected to have an impact on our liquidity or debt covenants; however, it is a reflection of the overall downturn in our industry, drop in oil prices in the fourth quarter of 2014 and decline in our projected future cash flows. We also performed an impairment test on our drilling rigs in Colombia. Our net book value in these rigs was $87.5 million as of December 31, 2014 and our analysis indicated that no impairment exists.

The most significant assumptions used in our analysis are the expected margin per day and utilization, as well as the estimated proceeds upon any future sale or disposal of the rig. 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.

If the demand for our drilling services remains at current levels or declines further and any of our rigs become idle for an extended amount of time, then our estimated cash flows may further decrease, and the probability of a near term sale may increase. If any of the foregoing were to occur, we may incur additional impairment charges.

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

We consider the recognition of revenues and costs on turnkey contracts to be critical accounting estimates. For these types of contracts, we recognize revenues and accrue estimated costs based on our estimate of the number of days to complete each contract and our estimate of the total costs to complete the contract. Revenues and costs during a reporting period could be affected for contracts in progress at the end of a reporting period which have not been completed before our financial statements for that period are released.

Our initial cost estimates for turnkey contracts do not include cost estimates for risks such as stuck drill pipe or loss of circulation. When we encounter, during the course of our drilling operations, conditions unforeseen in the preparation of our original cost estimate, we increase our cost estimate to complete the contract. If we anticipate a loss on a contract in progress at the end of a reporting period due to a change in our cost estimate, we accrue the entire amount of the estimated loss, including all costs that are included in our revised estimated cost to complete that contract, in our consolidated statement of operations for that reporting period. However, our actual costs could substantially exceed our estimated costs if we encounter problems such as lost circulation, stuck drill pipe or an underground blowout on contracts still in progress subsequent to the release of the financial statements.

We believe that our experienced management team, our knowledge of geologic formations in our areas of operations, the condition of our drilling equipment and our experienced crews have previously enabled us to make reasonable cost estimates and complete contracts according to our drilling plan. While we do bear the risk of loss for cost overruns and other events that are not specifically provided for in our initial cost estimates, our pricing of turnkey contracts takes such risks into consideration. We are more likely to encounter losses on turnkey contracts in periods in which revenue rates are lower for all types of contracts. However, during periods of reduced demand for drilling rigs, our overall profitability on turnkey contracts has historically exceeded our profitability on daywork contracts.

We incurred a total loss of $1.2 million on 13 of the 106 turnkey contracts which were initiated and completed during the year ended December 31, 2014. During the year ended December 31, 2013, we experienced a loss of approximately $17,000 on one turnkey contract completed and we did not experience a loss on any of the turnkey contracts completed during 2012. As of December 31, 2014, we had $0.8 million of unbilled receivables related to four turnkey contracts that were in progress at year-end, which were completed prior to the issuance of these financial statements.

We estimate an allowance for doubtful accounts based on the creditworthiness of our clients as well as general economic conditions. We evaluate the creditworthiness of our clients based on commercial credit reports, trade references, bank references, financial information, production information and any past experience we have with the client. Consequently, any change in those factors could affect our estimate of our allowance for doubtful accounts. In some instances, we require new clients to establish escrow accounts or make prepayments. We had an allowance for doubtful accounts of $2.5 million at December 31, 2014.

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.

With the significant decline in oil prices over the recent months, we performed impairment testing on all the mechanical and lower horsepower drilling rigs in our fleet. In order to estimate our future undiscounted cash flows from the use and eventual disposition of these assets, we incorporated probabilities of selling these rigs in the near term, versus working them at a significantly reduced expected rate of utilization through the end of their remaining useful lives. The most significant assumptions used in our analysis are the expected margin per day and utilization, as well as the estimated proceeds upon any future sale or disposal of the rig. 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.

As of December 31, 2014, we had $87.3 million of deferred tax assets related to foreign and domestic net operating loss and AMT credit carryforwards available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we only recognize a tax benefit to the extent of taxable income that we expect to earn in the jurisdiction in future periods. We estimate that our operations will result in taxable income in excess of our net operating losses and we expect to apply the net operating losses against the current year taxable income and taxable income that we have estimated in future periods.

Our accrued insurance premiums and deductibles as of December 31, 2014 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $3.4 million and our workers' compensation, general liability and auto liability insurance of approximately $9.0 million. We have stop-loss coverage of $200,000 per covered individual per year under our health insurance and a deductible of $500,000 per occurrence under our workers' compensation insurance. We have a deductible of $250,000 per occurrence under both our general liability insurance and auto liability insurance. We accrue for these costs as claims are incurred using an actuarial calculation that is based on industry and our company's historical claim development data, and we accrue the costs of administrative services associated with claims processing.

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

Recently Issued Accounting Standards

Discontinued Operations. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-08, Discontinued Operations (Topic 360): *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. This update, among other things, raises the threshold for a disposal to qualify for discontinued operations accounting and requires additional disclosures about disposals. We chose early adoption of this guidance beginning July 1, 2014.

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

Item 7A. 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 December 31, 2014, we had $155.0 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 $1.6 million, and a corresponding increase or decrease, respectively, in net income of approximately $1.0 million during the year ended December 31, 2014. 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, 2014.

Foreign Currency Risk

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

The impact of currency rate changes on our Colombian Peso denominated transactions and balances resulted in foreign currency losses of $5.8 million for the year ended December 31, 2014.

Item 8. Financial Statements and Supplementary Data

PIONEER ENERGY SERVICES CORP.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Pioneer Energy Services Corp.:

We have audited the accompanying consolidated balance sheets of Pioneer Energy Services Corp. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pioneer Energy Services Corp. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Pioneer Energy Services Corp.'s internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for discontinued operations in 2014 due to the adoption of Accounting Standards Update No. 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*.

/s/ KPMG LLP

San Antonio, Texas
February 17, 2015

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Pioneer Energy Services Corp.:

We have audited Pioneer Energy Services Corp.'s internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Pioneer Energy Services Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Pioneer Energy Services Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Pioneer Energy Services Corp. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 17, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

San Antonio, Texas
February 17, 2015

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 34,924	$ 27,385
Receivables:		
Trade, net of allowance for doubtful accounts	136,161	115,908
Unbilled receivables	38,002	49,535
Insurance recoveries	10,900	8,607
Income taxes and other	5,138	2,310
Deferred income taxes	10,998	13,092
Inventory	14,117	13,232
Assets held for sale	9,909	—
Prepaid expenses and other current assets	8,925	9,311
Total current assets	269,074	239,380
Property and equipment, at cost	1,702,273	1,724,124
Less accumulated depreciation	845,732	786,467
Net property and equipment	856,541	937,657
Intangible assets, net of accumulated amortization	24,223	32,194
Noncurrent deferred income taxes	2,753	1,156
Other long-term assets	18,998	19,236
Total assets	$ 1,171,589	$ 1,229,623
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 64,305	$ 43,718
Current portion of long-term debt	27	2,847
Deferred revenues	3,315	699
Accrued expenses:		
Payroll and related employee costs	40,058	30,020
Insurance premiums and deductibles	12,829	10,940
Insurance claims and settlements	10,900	8,607
Interest	5,432	12,275
Other	10,326	11,727
Total current liabilities	147,192	120,833
Long-term debt, less current portion	455,053	499,666
Noncurrent deferred income taxes	69,578	84,636
Other long-term liabilities	4,702	6,055
Total liabilities	676,525	711,190
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock $.10 par value; 100,000,000 shares authorized; 63,820,126 and 62,534,636 shares outstanding at December 31, 2014 and 2013, respectively.	6,414	6,275
Additional paid-in capital	472,457	456,812
Treasury stock, at cost; 317,103 and 219,304 shares at December 31, 2014 and 2013, respectively	(3,030)	(1,895)
Accumulated earnings	19,223	57,241
Total shareholders' equity	495,064	518,433
Total liabilities and shareholders' equity	$ 1,171,589	$ 1,229,623

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2014	2013	2012
	(in thousands, except per share data)		
Revenues:			
Drilling services	$ 516,473	$ 528,327	$ 498,867
Production services	538,750	431,859	420,576
Total revenues	1,055,223	960,186	919,443
Costs and expenses:			
Drilling services	345,862	351,630	333,846
Production services	340,102	277,625	252,775
Depreciation and amortization	183,376	187,918	164,717
General and administrative	103,385	94,183	85,603
Bad debt expense (recovery)	1,445	767	(440)
Impairment charges	73,025	54,292	1,131
Gain on sale of fishing and rental services operations	(10,702)	—	—
Gain on litigation	(5,254)	—	—
Total costs and expenses	1,031,239	966,415	837,632
Income (loss) from operations	23,984	(6,229)	81,811
Other (expense) income:			
Interest expense, net of interest capitalized	(38,781)	(48,310)	(37,049)
Loss on extinguishment of debt	(31,221)	—	—
Other	(3,304)	(1,239)	1,624
Total other expense	(73,306)	(49,549)	(35,425)
Income (loss) before income taxes	(49,322)	(55,778)	46,386
Income tax (expense) benefit	11,304	19,846	(16,354)
Net income (loss)	$ (38,018)	$ (35,932)	$ 30,032
Income (loss) per common share—Basic	$ (0.60)	$ (0.58)	$ 0.49
Income (loss) per common share—Diluted	$ (0.60)	$ (0.58)	$ 0.48
Weighted average number of shares outstanding—Basic	63,161	62,213	61,780
Weighted average number of shares outstanding—Diluted	63,161	62,213	62,762

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Shares		Amount		Additional Paid In Capital	Accumulated Earnings	Total Shareholders' Equity
	Common	Treasury	Common	Treasury			
			(In thousands)				
Balance as of December 31, 2011	61,877	(95)	$ 6,188	$ (904)	$ 442,020	$ 63,141	$ 510,445
Net income	—	—	—	—	—	30,032	30,032
Exercise of options and related income tax effect	172	—	17	—	676	—	693
Purchase of treasury stock	—	(40)	—	(360)	—	—	(360)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(449)	—	(449)
Issuance of restricted stock	117	—	12	—	(12)	—	—
Stock-based compensation expense	—	—	—	—	7,319	—	7,319
Balance as of December 31, 2012	62,166	(135)	$ 6,217	$ (1,264)	$ 449,554	$ 93,173	$ 547,680
Net loss	—	—	—	—	—	(35,932)	(35,932)
Exercise of options and related income tax effect	271	—	27	—	1,239	—	1,266
Purchase of treasury stock	—	(85)	—	(631)	—	—	(631)
Income tax effect of restricted stock vesting	—	—	—	—	(265)	—	(265)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(56)	—	(56)
Issuance of restricted stock	316	—	31	—	(31)	—	—
Stock-based compensation expense	—	—	—	—	6,371	—	6,371
Balance as of December 31, 2013	62,753	(220)	$ 6,275	$ (1,895)	$ 456,812	$ 57,241	$ 518,433
Net loss	—	—	—	—	—	(38,018)	(38,018)
Exercise of options and related income tax effect	929	—	93	—	8,275	—	8,368
Purchase of treasury stock	—	(97)	—	(1,135)	—	—	(1,135)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(201)	—	(201)
Issuance of restricted stock	455	—	46	—	(46)	—	—
Stock-based compensation expense	—	—	—	—	7,617	—	7,617
Balance as of December 31, 2014	64,137	(317)	$ 6,414	$ (3,030)	$ 472,457	$ 19,223	$ 495,064

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2014	2013	2012
		(in thousands)	
Cash flows from operating activities:			
Net income (loss)	$ (38,018)	$ (35,932)	$ 30,032
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	183,376	187,918	164,717
Allowance for doubtful accounts	1,445	801	76
Write-off of obsolete inventory	331	152	—
Gain on dispositions of property and equipment	(1,729)	(1,421)	(1,199)
Stock-based compensation expense	7,617	6,371	7,319
Amortization of debt issuance costs, discount and premium	2,669	3,095	2,985
Gain on sale of fishing and rental services operations	(10,702)	—	—
Loss on extinguishment of debt	31,221	—	—
Impairment charges	73,025	54,292	1,131
Deferred income taxes	(14,761)	(22,125)	13,303
Change in other long-term assets	2,958	(5,741)	(3,865)
Change in other long-term liabilities	(1,352)	(1,928)	(1,173)
Changes in current assets and liabilities:			
Receivables	(11,993)	(16,168)	(12,807)
Inventory	(1,068)	(1,273)	(927)
Prepaid expenses and other current assets	(55)	3,729	(1,266)
Accounts payable	7,037	(166)	2,431
Deferred revenues	2,616	(3,181)	(86)
Accrued expenses	424	6,157	(1,305)
Net cash provided by operating activities	233,041	174,580	199,366
Cash flows from investing activities:			
Purchases of property and equipment	(175,378)	(165,356)	(364,324)
Proceeds from sale of fishing and rental services operations	15,090	—	—
Proceeds from sale of property and equipment	8,370	13,836	3,093
Proceeds from insurance recoveries	—	844	—
Net cash used in investing activities	(151,918)	(150,676)	(361,231)
Cash flows from financing activities:			
Debt repayments	(490,025)	(60,874)	(874)
Proceeds from issuance of debt	440,000	40,000	100,000
Debt issuance costs	(9,239)	(13)	(58)
Tender premium costs	(21,553)	—	—
Proceeds from exercise of options	8,368	1,266	693
Purchase of treasury stock	(1,135)	(631)	(360)
Net cash provided by (used in) financing activities	(73,584)	(20,252)	99,401
Net increase (decrease) in cash and cash equivalents	7,539	3,652	(62,464)
Beginning cash and cash equivalents	27,385	23,733	86,197
Ending cash and cash equivalents	$ 34,924	$ 27,385	$ 23,733
Supplementary disclosure:			
Interest paid	$ 43,690	$ 46,274	$ 44,317
Income tax paid	$ 5,012	$ 3,154	$ 731
Noncash investing and financing activity:			
Change in capital expenditure accruals	$ 12,743	$ (39,936)	$ 14,948

See accompanying notes to consolidated financial statements.

1. Organization and Summary of Significant Accounting Policies

Business

Pioneer Energy Services Corp. provides drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies throughout much of the onshore oil and gas producing regions of the United States and internationally in Colombia. We also provide coiled tubing and wireline services offshore in the Gulf of Mexico.

Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies through our six drilling divisions in the US and internationally in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on either a daywork or turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed.

Since October 2014, domestic and international oil prices have declined significantly to historically low price levels resulting in a downturn in our industry. As a result, we performed an impairment evaluation of all our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*, which resulted in $71.0 million of impairment charges to reduce the carrying value of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value.

Mechanical and lower horsepower drilling rigs are the most impacted by the industry downturn and are typically the first rigs to become idle. As of December 31, 2014, we owned a total of 31 mechanical and lower horsepower electric drilling rigs, which includes the nine rigs that were idle and classified as held for sale as of year-end and 15 rigs that we expect to place as held for sale during the first quarter of 2015, after their current contracts are completed. In January and February 2015, we sold six of these drilling rigs. (See Note 14, *Subsequent Events*.)

The following is a summary of our drilling rig counts as of December 31, 2014 and February 1, 2015.

	Drilling Rigs Owned	Drilling Rigs Held for Sale	Drilling Rig Fleet Count
As of December 31, 2014	62	(9)	53
As of February 1, 2015	59	(12)	47

As of February 1, 2015, the drilling rigs in our fleet are assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
West Texas	10
North Dakota	9
Utah	4
Appalachia	3
Colombia	8
	47

We are currently constructing five new-build 1,500 horsepower AC drilling rigs which we expect to deliver and begin operating under long-term drilling contracts in 2015, with the first two rigs to be deployed during the second quarter, two rigs in the third quarter, and the final rig by the end of the year. Excluding the rigs which we expect to sell in the near-term and considering the five new-build drilling rigs under construction, we expect to end 2015 with a drilling fleet of 43 rigs.

As of February 1, 2015, 40 of our 47 drilling rigs are earning revenues under drilling contracts, 29 of which are earning under term contracts. Four of our drilling rigs in Colombia are currently working under term contracts that extend through mid-2015 and we are actively marketing our other four rigs to multiple clients to diversify our client base in Colombia.

In response to the dramatic decline in oil prices during recent months, we have received early termination notices for 12 of our 29 drilling rigs that are earning revenues under term contracts. These 12 drilling rigs will be released upon completion of their current wells, all of which are expected to be completed by the end of the first quarter 2015, resulting in approximately $43.5 million of early termination payments which will be recognized as revenue over the remaining term of the contracts, $0.3 million of which was recognized in 2014.

Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. As of February 1, 2015, we have a fleet of 117 well servicing rigs consisting of 107 rigs with 550 horsepower and 10 rigs with 600 horsepower, all of which are currently operating or are being actively marketed. We currently provide wireline services and coiled tubing services with a fleet of 128 wireline units and 17 coiled tubing units. On September 17, 2014, we completed the disposition of our fishing and rental services operations.

Basis of Presentation

The accompanying 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 consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America.

In preparing the accompanying 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 fair value for impairment evaluations, our estimate of deferred taxes, our estimate of the liability relating to the self-insurance portion of our health and workers' compensation insurance, and our estimate of compensation related accruals.

In preparing the accompanying consolidated financial statements, we have reviewed events that have occurred after December 31, 2014, through the filing of this Form 10-K, for inclusion as necessary.

Drilling Contracts

Our drilling contracts generally provide for compensation on either a daywork or turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. Spot market contracts generally provide for the drilling of a single well and typically permit the client to terminate on short notice. We enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand. Currently, we have contracts with original terms of six months to four years in duration.

As of February 1, 2015, we have 29 drilling rigs earning under term contracts, which if not renewed prior to the end of their terms, will expire as follows:

	Total Term Contracts	Term Contract Expiration by Period Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years
United States	25	13	6	4	2
Colombia	4	4	—	—	—
	29	17	6	4	2

In response to the dramatic decline in oil prices during recent months, we have received early termination notices for 12 of our 29 drilling rigs that are earning revenues under term contracts. These 12 drilling rigs will be released upon completion of their current wells, all of which are expected to be completed by the end of the first quarter 2015, resulting in approximately $43.5 million of early termination payments which will be recognized as revenue over the remaining term of the contracts, $0.3 million of which was recognized in 2014.

Foreign Currencies

Our functional currency for our foreign subsidiary in Colombia is the U.S. dollar. 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. Gains and losses from remeasurement of foreign currency financial statements into U.S. dollars and from foreign currency transactions are included in other income or expense.

Revenue and Cost Recognition

Drilling Services—Our Drilling Services Segment earns revenues by drilling oil and gas wells for our clients under daywork or turnkey contracts, which usually provide for the drilling of a single well. Drilling contracts for individual wells are usually completed in less than 60 days. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. All of our revenues are recognized net of applicable sales taxes.

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

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

The risks to us under a turnkey contract are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors' services, supplies, cost escalations and personnel operations.

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

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

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

The assets “prepaid expenses and other current assets” and “other long-term assets” include the current and long-term portions of deferred mobilization costs for certain drilling contracts. The liabilities “deferred revenues” and “other long-term liabilities” include the current and long-term portions of deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized, including amounts collected for early terminations of long-term drilling contracts. As of December 31, 2014 we had $3.3 million and $1.2 million of current deferred revenues and costs, respectively. Our deferred mobilization costs and revenues primarily relate to prepayments of long-term drilling contracts in the US. Amortization of deferred mobilization revenues was $4.6 million, $5.3 million and $6.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Production Services—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.

Concentration of Clients—We derive a significant portion of our revenue from a limited number of major clients. For the years ended December 31, 2014, 2013 and 2012, our drilling and production services to our top three clients accounted for approximately 28%, 29%, and 25%, respectively, of our revenue, and in 2014, 2013 and 2012, one client, Whiting Petroleum Company, accounted for 12%, 13% and 10%, respectively, of our revenue.

Cash and Cash Equivalents

For purposes of the consolidated statements of cash flows, we consider all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. We had cash equivalents of $2.6 million and $0.7 million at December 31, 2014 and 2013, respectively, which consisted of investments in corporate and government money market accounts.

Trade Accounts Receivable

We record trade accounts receivable at the amount we invoice our clients. These accounts do not bear interest. The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our accounts receivable as of the balance sheet date. We determine the allowance based on the credit worthiness of our clients and general economic conditions. Consequently, an adverse change in those factors could affect our estimate of our allowance for doubtful accounts.

We review our allowance for doubtful accounts on a monthly basis. Our typical drilling contract provides for payment of invoices in 30 days. We generally do not extend payment terms beyond 30 days and have not extended payment terms beyond 90 days for any of our contracts in the last three fiscal years. Our production services terms generally provide for payment of invoices in 30 days. Balances more than 90 days past due are reviewed individually for collectability. We charge off account balances against the allowance after we have exhausted all reasonable means of collection and determined that the potential for recovery is remote. We do not have any off-balance sheet credit exposure related to our clients.

The changes in our allowance for doubtful accounts consist of the following (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Balance at beginning of year	$ 1,356	$ 1,044	$ 994
Increase in allowance charged to expense	1,445	801	76
Accounts charged against the allowance	(254)	(489)	(26)
Balance at end of year	$ 2,547	$ 1,356	$ 1,044

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 $38.0 million at December 31, 2014, of which $0.8 million related to turnkey drilling contract revenues, $32.8 million represented revenue recognized but not yet billed on daywork drilling contracts in progress at December 31, 2014 and $4.4 million related to unbilled receivables for our Production Services Segment. At December 31, 2013, our unbilled receivables totaled $49.5 million, of which $45.4 million represented revenue recognized but not yet billed on daywork drilling contracts in progress at December 31, 2013 and $4.1 million related to unbilled receivables for our Production Services Segment.

Inventories

Inventories primarily consist of drilling rig replacement parts and supplies held for use by our Drilling Services Segment’s operations in Colombia and supplies held for use by our Production Services Segment’s operations. Inventories are valued at the lower of cost (first in, first out or actual) or market value.

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 prepaid taxes in Colombia which are creditable against future income taxes and the current portion of deferred mobilization costs for certain drilling contracts that are recognized on a straight-line basis over the contract term.

Property and Equipment

Property and equipment are carried at cost less accumulated depreciation. Depreciation is provided for our assets over the estimated useful lives of the assets using the straight-line method. We record the same depreciation expense whether a rig is idle or working. We charge our expenses for maintenance and repairs to operating costs. We capitalize expenditures for renewals and betterments to the appropriate property and equipment accounts.

Intangible Assets

Our intangible assets consist of the following components as of December 31, 2014 and 2013 (amounts in thousands):

	December 31, 2014	December 31, 2013
Cost:		
Client relationships	$ 63,168	$ 63,168
Non-compete agreements	1,355	1,355
Accumulated amortization:		
Client relationships	(39,256)	(31,584)
Non-compete agreements	(1,044)	(745)
	$ 24,223	$ 32,194

Substantially all of our intangible assets were recorded in connection with the acquisitions of production services businesses and are subject to amortization. The cost of our client relationships are amortized using the straight-line method over their respective estimated economic useful lives which range from three to nine years. Amortization expense for our non-compete agreements is calculated using the straight-line method over the period of the agreements which range from three to seven years. Amortization expense was $8.0 million, $8.5 million and $8.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. Amortization expense is estimated to be approximately $7.9 million, $5.1 million, $3.8 million, $3.8 million and $3.6 million for the years ending December 31, 2015, 2016, 2017, 2018 and 2019, respectively. Actual amortization amounts may be different due to future acquisitions, impairments, changes in amortization periods, or other factors.

We evaluate for potential impairment of long-lived tangible and intangible assets subject to amortization when indicators of impairment are present. Circumstances that could indicate a potential impairment include significant adverse changes in industry trends, economic climate, legal factors, and an adverse action or assessment by a regulator. More specifically, significant adverse changes in industry trends include significant declines in revenue rates, utilization rates, oil and natural gas market prices and industry rig counts. In performing an impairment evaluation, we estimate the future undiscounted net cash flows from the use and eventual disposition of long-lived tangible and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for the individual reporting units (well servicing, wireline and coiled tubing). If the sum of the estimated future undiscounted net cash flows is less than the carrying amount of the asset group, then we would determine the fair value of the asset group. The amount of an impairment charge would be measured as the difference between the carrying amount and the fair value of these assets. The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment.

Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our long-lived tangible and intangible assets as of June 30, 2013. Our analysis resulted in a non-cash impairment charge of $3.1 million which we recognized during 2013 to reduce our intangible asset carrying value of client relationships. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain coiled tubing markets where we operate and a decline in our projected cash flows for the coiled tubing reporting unit. Due to continued increases in competition in certain coiled tubing markets and lower than anticipated operating results, we performed another impairment analysis of our long-lived tangible and intangible assets as of December 31, 2013, at which time we determined that the sum of the estimated future undiscounted net cash flows for our coiled tubing services reporting unit was in excess of the carrying amount and concluded that no impairment existed.

The most significant inputs used in our impairment analyses include the projected utilization and pricing of our coiled tubing services, which are classified as Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures.* 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. If we fail to meet the projected increases in utilization and pricing for our coiled tubing services, or in the event of significant unfavorable changes in the forecasted cash flows or key assumptions used in our analysis, the most significant of these being the projected utilization and pricing of our coiled tubing services, then we may incur a future impairment. Our coiled tubing services' operating results for the year ended December 31, 2014 exceeded our projections.

Our impairment analyses did not result in any impairment charges to our coiled tubing tangible long-lived assets, substantially all of which relates to our coiled tubing units and equipment. As discussed further below, we also recorded a non-cash impairment charge during 2013 to reduce the carrying value of goodwill to zero.

Goodwill

In connection with the acquisition of the production services business from Go-Coil, we recorded $41.7 million of goodwill at December 31, 2011. Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our goodwill as of June 30, 2013. We used an income approach to estimate the fair value of our coiled tubing services reporting unit and determined that there was no remaining implied fair value attributable to goodwill. Accordingly, we recorded a non-cash impairment charge of $41.7 million during 2013 to reduce the carrying value of our goodwill to zero. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the increased competition in certain coiled tubing markets where we operate and a decline in our projected cash flows for the coiled tubing reporting unit.

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

Other Long-Term Assets

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

Other Current Liabilities

Our other accrued expenses include accruals for items such as property tax, sales tax, 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, deferred mobilization revenues, and other deferred liabilities.

Treasury Stock

Treasury stock purchases are accounted for under the cost method whereby the cost of the acquired common stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of treasury stock shares are credited or charged to additional paid in capital using the average cost method.

Stock-based Compensation

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

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the fair market value of our stock on the date of exercise over the exercise price of the options. In accordance with ASC Topic 718, we reported all excess tax benefits resulting from the exercise of stock options as financing cash flows in our consolidated statement of cash flows.

Income Taxes

We follow the asset and liability method of accounting for income taxes, under which we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. We measure our deferred tax assets and liabilities by using the enacted tax rates we expect to apply to taxable income in the years in which we expect to recover or settle those temporary differences. The effect of a change in tax rates on deferred tax assets and liabilities is reflected in income in the period during which the change occurs. A recent change in Colombia tax rates is described in more detail in Note 6, *Income Taxes*.

Recently Issued Accounting Standards

Discontinued Operations. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-08, Discontinued Operations (Topic 360): *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. This update, among other things, raises the threshold for a disposal to qualify for discontinued operations accounting and requires additional disclosures about disposals. We chose early adoption of this guidance beginning July 1, 2014.

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

Reclassifications

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

2. Sale of Fishing and Rental Services Operations

On September 17, 2014, we entered into an asset sales agreement with Basic Energy Services L.P. ("Basic") for the sale of our fishing and rental services (“F&R”) operations for total consideration of $16.1 million, subject to certain adjustments. The sales price consisted of $15.1 million of cash received at closing and $1.0 million to be held in escrow for a period of 180 days for potential claims due to Basic. Under the terms of the sales agreement, Basic purchased two real estate locations and all F&R tools and equipment for which we had a total net book value of $4.3 million at the date of sale. Basic also purchased certain other assets and assumed certain liabilities related to our F&R operations. In addition, Basic offered employment to the F&R employees and we agreed to provide transition services to Basic after the close of the transaction. We recognized a $10.7 million gain on the sale of our F&R operations, net of costs directly attributable to the sale. Net of income taxes, the gain was $6.6 million. Cash proceeds from the sale were used to repay long-term debt obligations.

For the nine months ended September 30, 2014, F&R operations represented approximately 1% of our consolidated revenues and approximately 1% of our consolidated pretax income. Total assets for F&R at the date of sale represented less than 1% of our total assets as of September 30, 2014. The sale of the F&R operations does not represent a strategic shift for our company and will not have a significant effect on our operating results. Therefore, the F&R operations does not represent discontinued operations based on the criteria of ASU No. 2014-08, "Discontinued Operations."

Balance sheet information for the F&R operations is as follows (amounts in thousands):

		December 31, 2013
Current assets	$	1,877
Property and equipment, less accumulated depreciation		6,132
Total assets	$	8,009
Current liabilities	$	919
Long term liabilities		1,452
Total liabilities	$	2,371

Statement of operations information for the F&R operations is as follows (amounts in thousands):

	Year ended December 31,					
	2014		2013		2012	
Revenues	$	7,828	$	12,459	$	13,327
Operating costs		5,097		8,000		8,146
F&R margin	$	2,731	$	4,459	$	5,181
Income (loss) before income taxes	$	(162)	$	242	$	1,177

3. Property and Equipment

Our total capital expenditures of $188.1 million during 2014 primarily relate to our five new-build drilling rigs which began construction during 2014, as well as unit additions to our production services fleets. As of December 31, 2014 and 2013, capital expenditures incurred for property and equipment not yet placed in service was $82.7 million and $19.4 million, respectively. During the years ended December 31, 2014, 2013 and 2012, we capitalized $0.7 million, $0.9 million and $10.2 million, respectively, of interest costs incurred primarily during the construction periods of new-build drilling rigs and other drilling equipment.

As of December 31, 2014 and 2013, the estimated useful lives and costs of our asset classes are as follows:

		December 31, 2014	December 31, 2013
	Lives	Cost (amounts in thousands)	
Drilling rigs and equipment	2 - 25	$ 1,168,404	$ 1,223,621
Well servicing rigs and equipment	3 - 20	232,771	205,409
Wireline units and equipment	2 - 10	146,748	128,800
Coiled tubing units and equipment	1 - 7	60,389	47,761
Fishing and rental tools and equipment	3 - 15	—	17,264
Vehicles	3 - 15	55,014	65,796
Office equipment	1 - 10	11,521	9,274
Buildings and improvements	2 - 40	25,007	23,931
Land	—	2,419	2,268
		$ 1,702,273	$ 1,724,124

We recorded gains on disposition of our property and equipment of $1.7 million, $1.4 million and $1.2 million during the years ended December 31, 2014, 2013 and 2012, respectively, in our drilling and production services costs and expenses. In February 2014, we completed the sale of our trucking assets for a sales price of $4.5 million which included a fleet of 40 trucks and related transportation equipment that we used to transport our drilling rigs to and from drilling sites. By owning our own trucks, we were historically able to reduce the overall cost and downtime between rig moves. However, with the industry trend toward pad drilling, we upgraded a number of our drilling rigs in recent years to equip them with walking or skidding systems, which enable the drilling rigs to move between wells in pad drilling, and thus operating our own trucking fleet became less beneficial. The net book value of the trucking assets sold was $3.4 million, for which we recognized a total gain of $1.1 million. During the second quarter of 2013, we sold two mechanical drilling rigs that were previously idle in our East Texas division, for which we recognized an associated gain of approximately $0.8 million. Additionally, we disposed of a total of four wireline units during 2013, as well as other wireline equipment.

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

Since October 2014, domestic and international oil prices have declined significantly to historically low price levels resulting in a downturn in our industry. As a result, we performed an impairment evaluation of all our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*, which resulted in $71.0 million of impairment charges to reduce the carrying value of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value.

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

As of December 31, 2014, we owned a total of 31 mechanical and lower horsepower electric drilling rigs, which includes the nine rigs that were idle and classified as held for sale as of year-end and 15 rigs that we expect to place as held for sale during the first quarter of 2015, after their current contracts are completed. (See Note 14, *Subsequent Events*.) With the significant decline in oil prices over the recent months, we performed impairment testing on all the mechanical and lower horsepower drilling rigs in our fleet. In order to estimate our future undiscounted cash flows from the use and eventual disposition of these assets, we incorporated probabilities of selling these rigs in the near term, versus working them at a significantly reduced expected rate of utilization through the end of their remaining useful lives. Our testing indicated that the carrying value of these assets was more than our estimated undiscounted cash flows, resulting in a total impairment of $71.0 million to reduce the carrying value of these assets to their estimated fair value of $34.0 million, which was based on market appraisals, which are considered Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures.*This impairment charge is not expected to have an impact on our liquidity or debt covenants; however, it is a reflection of the overall downturn in our industry, drop in oil prices in the fourth quarter of 2014 and decline in our projected future cash flows. We also performed an impairment test on our drilling rigs in Colombia. Our net book value in these rigs was $87.5 million as of December 31, 2014 and our analysis indicated that no impairment exists.

The most significant assumptions used in our analysis are the expected margin per day and utilization, as well as the estimated proceeds upon any future sale or disposal of the rig. 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.

If the demand for our drilling services remains at current levels or declines further and any of our rigs become idle for an extended amount of time, then our estimated cash flows may further decrease, and the probability of a near term sale may increase. If any of the foregoing were to occur, we may incur additional impairment charges.

Additionally, we recorded $2.0 million of impairment charges during the year ended December 31, 2014 to reduce the carrying values of certain other assets, which were placed as held for sale during the year, to their estimated fair values, based on expected sales price. As of December 31, 2014, our consolidated balance sheet reflects assets held for sale of $9.9 million, which represents the fair value of nine drilling rigs, four wireline units, two real estate properties and other drilling equipment. In January and February 2015, we sold six drilling rigs and one real estate property for $17.8 million. We did not incur any additional loss upon the sale of these assets. (See Note 14, *Subsequent Events*.)

During the years ended December 31, 2013 and 2012, we recorded impairment charges on our property and equipment of $9.5 million and $1.1 million, respectively. During the third quarter of 2013, we decided to place eight of our mechanical drilling rigs as held for sale, and we recognized an impairment loss of $9.2 million in order to reduce the carrying value of these assets to their estimated fair value, based on their sales price. The sales of all eight drilling rigs were completed in late October 2013 and we did not incur any additional gain or loss upon the sale of these rigs. We also recorded an impairment of $0.3 million during the third quarter of 2013 in association with our decision to sell certain production services equipment. In March 2012, we retired two mechanical drilling rigs, with most of their components to be used as spare parts, as well as two wireline units and other wireline equipment, and recognized an associated impairment charge of $1.1 million.

4. Debt

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

	December 31, 2014	December 31, 2013
Senior secured revolving credit facility	$ 155,000	$ 80,000
Senior notes	300,000	419,586
Other	80	2,927
	455,080	502,513
Less current portion	(27)	(2,847)
	$ 455,053	$ 499,666

Senior Secured Revolving Credit Facility

We have a credit agreement, as amended on September 22, 2014, with Wells Fargo Bank, N.A. and a syndicate of lenders which provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of $350 million, all of which matures on September 22, 2019 (the "Revolving Credit Facility"). In addition, at our request, and with the lenders' consent, the aggregate commitments of the lenders under the Revolving Credit Facility may be increased up to an additional $100 million provided that no default exists, all representations and warranties are true and correct, and compliance with financial covenants as set forth in the Revolving Credit Facility is met immediately prior to and after giving effect thereto. The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and letter of credit exposure, but in no event will reduce the borrowing availability under the Revolving Credit Facility to less than $350 million.

Borrowings under the Revolving Credit Facility bear interest, at our option, at the LIBOR rate or at the bank prime rate, plus an applicable per annum margin that ranges from 2.0% to 3.0% and 1.0% to 2.0%, respectively. The LIBOR margin and bank prime rate margin currently in effect are 2.25% and 1.25%, respectively. The Revolving Credit Facility requires a commitment fee due quarterly based on the average daily unused amount of the commitments of the lenders, a fronting fee due for each letter of credit issued, and a quarterly letter of credit fee due based on the average undrawn amount of letters of credit outstanding during such period.

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

As of February 1, 2015, we had $150.0 million outstanding under our Revolving Credit Facility and $18.5 million in committed letters of credit, which resulted in borrowing availability of $181.5 million under our Revolving Credit Facility. There are no limitations on our ability to access this borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. At December 31, 2014, we were in compliance with our financial covenants under the Revolving Credit Facility. Our total consolidated leverage ratio was 1.8 to 1.0, our senior consolidated leverage ratio was 0.7 to 1.0, and our interest coverage ratio was 6.7 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

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

The Revolving Credit Facility does not restrict capital expenditures or repurchases of capital stock as long as (a) no event of default exists under the Revolving Credit Facility or would result from such capital expenditures or repurchases of capital stock, (b) after giving effect to such capital expenditures or repurchases of capital stock there is availability under the Revolving Credit Facility equal to or greater than $25 million and (c) the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is less than 2.00 to 1.00. In addition, the repurchase of capital stock requires, on a pro-forma basis, compliance with the maximum total leverage ratio and minimum interest coverage ratio as set forth in the Revolving Credit Facility, both before and after giving effect to such repurchase. If the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter is equal to or greater than 2.00 to 1.00, then capital expenditures are limited to $100 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $30 million.

At December 31, 2014, our senior consolidated leverage ratio was not greater than 2.00 to 1.00 and therefore, we were not subject to the capital expenditure threshold restrictions listed above.

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

Senior Notes

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

On November 21, 2011, we issued $175 million of unregistered Senior Notes (the “2011 Senior Notes”). The 2011 Senior Notes have the same terms and conditions as the 2010 Senior Notes. The 2011 Senior Notes were sold with an original issue premium of $1.8 million that was based on 101% of their face value, which will result in an effective yield to maturity of approximately 9.66%. On November 21, 2011, we received $172.7 million of net proceeds from the issuance of the 2011 Senior Notes, including the original issue premium, and after $4.1 million of deductions were made for underwriters' fees and other debt offering costs. A portion of the net proceeds were used to fund the acquisition of 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 redeemed $99.5 million of the 2010 and 2011 Senior Notes for a total consideration of $1,055.08 for each $1,000 principal amount redeemed. In May and October 2014, we redeemed an additional $200.5 million and $125.0 million, respectively, in aggregate principal amount of the 2010 and 2011 Senior Notes at a redemption price equal to 104.938% of the principal amount, plus accrued and unpaid interest on the notes redeemed. Related to these redemptions, we recognized a loss on debt extinguishment of approximately $31.2 million during 2014, which includes redemption premiums of $21.6 million, $4.8 million of net unamortized discount and $4.8 million of unamortized debt issuance costs.

On March 18, 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. On March 18, 2014, we received $293.9 million of net proceeds from the issuance of the 2014 Senior Notes after deductions were made for the $6.1 million for underwriters' fees and other debt offering costs. The net proceeds were used to fund the tender and redemption of 2010 and 2011 Senior Notes in March and May 2014.

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 "2014 Indenture") plus any accrued and unpaid interest and any additional interest (as defined in the 2014 Indenture) thereon to the date of redemption. Prior to March 15, 2017, we may also redeem the 2014 Senior Notes, in whole or in part, at a "make-whole" redemption price specified in the 2014 Indenture, plus any accrued and unpaid interest and any additional interest thereon to the date of redemption. In addition, prior to March 15, 2017, we may, on one or more occasions, redeem up to 35% of the aggregate principal amount of the 2014 Senior Notes at a redemption price equal to 106.125% of the principal amount thereof, plus accrued and unpaid interest and additional interest, if any, to the redemption date, with the net cash proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the 2014 Senior Notes remains outstanding after the occurrence of such redemption and that the redemption occurs within 120 days of the date of the closing of such equity offering.

In accordance with a registration rights agreement with the holders of our 2014 Senior Notes, we filed an exchange offer registration statement on Form S-4 with the Securities and Exchange Commission that became effective on October 2, 2014, respectively. 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 our ability and the ability of certain of our subsidiaries 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 15, *Guarantor/Non-Guarantor Condensed Consolidated Financial Statements*.)

Other Debt

Our other debt consists of a capital lease obligation for equipment with monthly payments due through November 2016.

Debt Issuance Costs

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

Capitalized debt costs related to the issuance of our long-term debt were approximately $9.8 million and $7.5 million as of December 31, 2014 and 2013, respectively. We recognized approximately $2.1 million of associated amortization during each of the years ended December 31, 2014, 2013 and 2012, which excludes the $4.8 million of debt costs recognized as loss on extinguishment of debt.

5. Leases

We lease our corporate office facilities in San Antonio, Texas at a payment escalating from $41,264 per month in January 2015 to $50,246 per month in December 2020. We recognize rent expense on a straight-line basis for our corporate office lease. We also lease real estate at 51 other locations, which are primarily used for field offices and storage and maintenance yards, and we lease vehicles, office and other equipment under non-cancelable operating leases, most of which contain renewal options and some of which contain escalation clauses.

Future lease obligations required under non-cancelable operating leases as of December 31, 2014 were as follows (amounts in thousands):

Year ended December 31,	
2015	$ 4,441
2016	3,282
2017	2,709
2018	1,705
2019	1,288
Thereafter	1,509
	$ 14,934

Rent expense under operating leases for the years ended December 31, 2014, 2013 and 2012 was $5.9 million, $6.0 million and $5.6 million, respectively.

6. Income Taxes

The jurisdictional components of income (loss) before income taxes consist of the following (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Domestic	$ (49,050)	$ (66,147)	$ 42,194
Foreign	(272)	10,369	4,192
Income (loss) before income tax	$ (49,322)	$ (55,778)	$ 46,386

The components of our income tax expense (benefit) consist of the following (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Current tax:			
Federal	$ (112)	$ (380)	$ 236
State	1,325	879	1,214
Foreign	3,149	2,302	1,479
	4,362	2,801	2,929
Deferred taxes:			
Federal	(17,438)	(21,034)	15,013
State	1,304	(3,520)	(749)
Foreign	468	1,907	(839)
	(15,666)	(22,647)	13,425
Income tax expense (benefit)	$ (11,304)	$ (19,846)	$ 16,354

The difference between the income tax expense (benefit) and the amount computed by applying the federal statutory income tax rate of 35% to income (loss) before income taxes consists of the following (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Expected tax expense (benefit)	$ (17,263)	$ (19,522)	$ 16,235
State income taxes	1,214	(1,717)	302
Incentive stock options	(208)	66	43
Net tax benefits and nondeductible expenses in foreign jurisdictions	957	(92)	533
Foreign currency translation gain (loss)	2,699	617	(1,414)
Nondeductible expenses for tax purposes	920	863	770
Valuation allowance	496	—	(206)
Other, net	(119)	(61)	91
Income tax expense (benefit)	$ (11,304)	$ (19,846)	$ 16,354

Income tax expense (benefit) was allocated as follows (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Results of operations	$ (11,304)	$ (19,846)	$ 16,354
Stockholders' equity	201	321	449
Income tax expense (benefit)	$ (11,103)	$ (19,525)	$ 16,803

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements. The components of our deferred income tax assets and liabilities were as follows (amounts in thousands):

	Year ended December 31,	
	2014	2013
Deferred tax assets:		
Capital loss carryforward	$ 1,009	$ 1,008
Intangibles	33,542	36,442
Employee benefits and insurance claims accruals	12,146	9,332
Accounts receivable reserve	908	501
Employee stock-based compensation	8,440	8,905
Accrued expenses not deductible for tax purposes	1,391	749
Accrued revenue not income for book purposes	429	942
Federal and state net operating loss and AMT credit carryforward	84,782	94,605
Foreign net operating loss carryforward	2,562	3,411
	145,209	155,895
Valuation allowance	(1,504)	(1,008)
Total deferred tax assets	143,705	154,887
Deferred tax liabilities:		
Property and equipment	199,532	225,275
Total deferred tax liabilities	199,532	225,275
Net deferred tax liabilities	$ 55,827	$ 70,388

In assessing the realizability of 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. Based on the expectation of future taxable income and that the deductible temporary differences will offset existing taxable temporary differences, we believe it is more likely than not that we will realize the benefits of these deductible temporary differences, with the exception of the items noted below.

As of December 31, 2014, we had a $1.0 million deferred tax asset related to the sale of our ARPSs investments which will represent a capital loss for tax treatment purposes. We can recognize a tax benefit associated with this loss to the extent of capital gains we expect to earn in future periods. We recorded a valuation allowance to fully offset our deferred tax asset relating to this capital loss since we believe capital gains are not likely in future periods. In addition, we have set up a $0.5 million valuation allowance against net operating losses in certain states.

As of December 31, 2014, we had $84.8 million and $2.6 million of deferred tax assets related to domestic and foreign net operating losses, respectively, that are available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we only recognize a tax benefit to the extent of taxable income that we expect to earn in the jurisdiction in future periods. We estimate that our operations will result in taxable income in excess of our net operating losses and we expect to apply the net operating losses against taxable income that we have estimated in future periods. The domestic net operating losses can be used to offset future domestic taxable income through 2033, while the majority of the foreign net operating losses can be carried forward indefinitely.

Deferred income taxes have not been provided on the future tax consequences attributable to difference between the financial statements carrying amounts of existing assets and liabilities and the respective tax bases of our foreign subsidiary based on the determination that such differences are essentially permanent in duration in that the earnings of the subsidiary is expected to be indefinitely reinvested in foreign operations. As of December 31, 2014, the cumulative undistributed earnings/loss of the subsidiary was approximately a $11.6 million loss. If earnings were not considered indefinitely reinvested, deferred income taxes would have been recorded after consideration of foreign tax credits. It is not practicable to estimate the amount of additional tax that might be payable on earnings, if distributed.

On December 26, 2012, Colombia enacted a tax reform bill that, among other things, decreased the corporate tax rate from 33% to 25%, but also added a new 9% tax for equality, which results in a combined tax rate of 34%. Net operating losses cannot be utilized against the new 9% tax for equality, and therefore the associated deferred tax asset must now be based on the lower 25% corporate tax rate only. Other deferred tax assets and liabilities must now be based on the higher combined income tax rate of 34%. Included in our 2012 deferred foreign tax expense is a $1.7 million expense to adjust our Colombian net deferred tax assets and liabilities for the change in rates.

On December 23, 2014, the Colombian government enacted a tax reform bill that among other things, increased the tax for equality ("CREE") rate from 9% to 14% in 2015, 15% in 2016, 17% in 2017 and 18% in 2018. Deferred tax assets and liabilities (with the exception of net operating losses) must now be based on the higher combined income tax rate and CREE rate of 39% in 2015, 40% in 2016, 42% in 2017 and 43% in 2018. Included in our 2014 deferred foreign tax expense (benefit) is a $0.2 million benefit to adjust our Colombian net deferred tax assets and liabilities for the change in rates. In addition, a new net-worth tax was enacted for all Colombian entities. The tax is calculated based on an entity's net equity as of January 1, 2015. The tax expense will be recognized when the net-worth tax is assessed, beginning annually from 2015 through 2017. Based on our Colombian operation's net equity, our net-worth tax obligations are expected to be approximately $1.4 million, $1.2 million and $0.5 million for the years ended December 31, 2015, 2016 and 2017, respectively. The net worth tax is not deductible for income tax purposes.

We have no unrecognized tax benefits relating to ASC Topic 740 and no unrecognized tax benefit activity during the year ended December 31, 2014.

We adopted a policy to record interest and penalty expense related to income taxes as interest and other expense, respectively. At December 31, 2014, no interest or penalties have been or are required to be accrued. Our open tax years for our federal income tax returns in the United States are for the years ended December 31, 2011 to 2013. Our open tax years for our income tax returns in Colombia are for the years ended December 31, 2009 to 2013.

7. Fair Value of Financial Instruments

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

At December 31, 2014 and December 31, 2013, 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 December 31, 2014 and December 31, 2013 (amounts in thousands):

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	$ 455,080	$ 415,785	$ 502,513	$ 538,074

8. Earnings Per Common Share

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

	Year ended December 31,		
	2014	2013	2012
Basic			
Net income (loss)	$ (38,018)	$ (35,932)	$ 30,032
Weighted-average shares	63,161	62,213	61,780
Income (loss) per common share—Basic	$ (0.60)	$ (0.58)	$ 0.49
Diluted			
Net income (loss)	$ (38,018)	$ (35,932)	$ 30,032
Weighted-average shares			
Outstanding	63,161	62,213	61,780
Diluted effect of outstanding stock options, restricted stock and restricted stock unit awards	—	—	982
	63,161	62,213	62,762
Income (loss) per common share—Diluted	$ (0.60)	$ (0.58)	$ 0.48

Potentially dilutive stock options, restricted stock and restricted stock unit awards representing a total of 3,949,464, 5,507,765 and 4,311,645 shares of common stock for the years ended December 31, 2014, 2013 and 2012, respectively, were excluded from the computation of diluted weighted average shares outstanding due to their antidilutive effect.

9. Equity Transactions and Stock-Based Compensation Plans

Equity Transactions

In May 2012, we filed a registration statement that permits us to sell equity or debt in one or more offerings up to a total dollar amount of $300 million. As of December 31, 2014, the entire $300 million under the shelf registration statement is available for equity or debt offerings. In the future, we may consider equity or debt offerings, as appropriate, to meet our liquidity needs.

Stock-based Compensation Plans

We have stock-based award plans that are administered by the Compensation Committee of our Board of Directors, which selects persons eligible to receive awards and determines the number of stock options, restricted stock, or restricted stock units subject to each award and the terms, conditions and other provisions of the awards. At December 31, 2014, the total shares available for future grants to employees and directors under existing plans were 2,303,381, of which no more than 1,669,117 may be granted in the form of restricted stock or restricted stock unit awards.

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

The following table summarizes the compensation expense recognized for stock option, restricted stock and restricted stock unit awards during the years ended December 31, 2014, 2013 and 2012 (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Stock option awards	$ 1,275	$ 1,771	$ 2,962
Restricted stock awards	548	576	628
Restricted stock unit awards	5,794	4,024	3,729
	$ 7,617	$ 6,371	$ 7,319

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. The following table summarizes the assumptions used in the Black-Scholes option pricing model based on a weighted-average calculation for the years ended December 31, 2014, 2013 and 2012:

	Year ended December 31,		
	2014	2013	2012
Expected volatility	66%	66%	70%
Risk-free interest rates	1.7%	1.0%	0.8%
Expected life in years	5.49	5.53	5.12
Grant-date fair value	$4.87	$4.36	$5.02

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

The following table represents stock option activity from December 31, 2012 through December 31, 2014:

	Number of Shares	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contract Life in Years
Outstanding stock options as of December 31, 2012	5,649,991	$10.09	
Granted	220,656	7.58	
Forfeited	(67,500)	16.02	
Exercised	(270,934)	4.67	
Outstanding stock options as of December 31, 2013	5,532,213	$10.18	
Granted	221,440	8.44	
Forfeited	(155,100)	14.82	
Exercised	(928,777)	9.01	
Outstanding stock options as of December 31, 2014	4,669,776	$10.18	4.7
Stock options exercisable as of December 31, 2014	4,124,506	$10.42	4.2

At December 31, 2014, the aggregate intrinsic value of stock options outstanding was $1.4 million and the aggregate intrinsic value of stock options exercisable was $1.4 million. Intrinsic value is the difference between the exercise price of a stock option and the closing market price of our common stock, which was $5.54 on December 31, 2014.

The following table summarizes our nonvested stock option activity from December 31, 2012 through December 31, 2014:

	Number of Shares	Weighted-Average Grant-Date Fair Value Per Share
Nonvested stock options as of December 31, 2012	1,130,844	$4.89
Granted	220,656	4.36
Vested	(594,459)	4.88
Nonvested stock options as of December 31, 2013	757,041	$4.74
Granted	221,440	4.87
Vested	(433,211)	4.77
Nonvested stock options as of December 31, 2014	545,270	$4.77

At December 31, 2014, there was $0.6 million of unrecognized compensation cost relating to stock options which is expected to be recognized over a weighted-average period of 0.6 years.

In January 2015, our Board of Directors approved the grant of stock options representing 338,638 shares of common stock to officers and employees that will vest over a three-year period.

Restricted Stock

Historically, we have generally granted restricted stock awards that vest over a three-year period with a fair value based on the closing price of our common stock on the date of the grant. However, beginning in 2013, we began granting restricted stock awards with a vesting period of one year. When restricted stock awards are granted, or when restricted stock unit awards are converted to restricted stock, shares of our common stock are considered issued, but subject to certain restrictions.

The following table summarizes our restricted stock activity from December 31, 2012 through December 31, 2014:

	Number of Shares	Weighted-Average Grant-Date Fair Value per Share
Nonvested restricted stock as of December 31, 2012	142,820	$8.67
Granted	61,248	7.51
Vested	(98,864)	8.47
Nonvested restricted stock as of December 31, 2013	105,204	$8.18
Granted	32,100	14.33
Vested	(88,620)	8.20
Nonvested restricted stock as of December 31, 2014	48,684	$12.20

At December 31, 2014, there was $0.2 million of unrecognized compensation cost relating to restricted stock awards which is expected to be recognized over a weighted-average period of 0.4 years.

Restricted Stock Units

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

Our time-based RSUs generally vest over a three-year period, with fair values based on the closing price of our common stock on the date of grant.

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 2011, 2012 and 2013, and half of the performance-based RSUs granted during 2014, are subject to a market condition based on total shareholder return, 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 EBITDA and return on capital employed, 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 2014, we determined that 116.6% of the target number of shares granted during 2011 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, 2011 through December 31, 2013, resulting in an additional 22,091 shares being issued. The performance-based RSUs granted during 2011 vested and were converted to common stock at the end of April 2014.

As of December 31, 2014, we estimated that our actual achievement level for the performance-based RSUs granted during 2012, 2013 and 2014 will be approximately 117%, 100% and 110% of the predetermined performance conditions, respectively. Therefore, the outstanding 861,812 restricted stock units would be adjusted to represent 922,845 shares of our common stock if these achievement levels are maintained through the applicable performance periods.

The following table summarizes our restricted stock unit activity from December 31, 2012 through December 31, 2014:

	Time-Based Award		Performance-Based Award	
	Number of Time-Based Award Units	Weighted-Average Grant-Date Fair Value per Unit	Number of Performance-Based Award Units	Weighted-Average Grant-Date Fair Value per Unit
Nonvested restricted stock units as of December 31, 2012	531,526	$9.16	355,051	$9.99
Granted	406,027	7.59	346,731	8.34
Vested	(254,629)	9.82	—	—
Forfeited	(55,212)	8.60	(28,020)	8.81
Nonvested restricted stock units as of December 31, 2013	627,712	$7.93	673,762	$9.19
Granted	360,665	8.64	400,503	9.67
Achieved performance adjustment	—	—	22,091	10.23
Vested	(267,430)	8.16	(155,647)	10.23
Forfeited	(45,868)	8.07	(78,897)	9.30
Nonvested restricted stock units as of December 31, 2014	675,079	$8.21	861,812	$9.24

At December 31, 2014, there was $5.0 million of unrecognized compensation cost relating to restricted stock unit awards which is expected to be recognized over a weighted-average period of 1.1 years.

In January 2015, our Board of Directors approved the grant of restricted stock units representing 581,192 shares of common stock to officers and employees that will vest over a three-year period.

10. Employee Benefit Plans and Insurance

We maintain a 401(k) retirement plan for our eligible employees. Under this plan, we may make a matching contribution, on a discretionary basis, equal to a percentage of each eligible employee's annual contribution, which we determine annually. Our matching contributions for the years ended December 31, 2014, 2013 and 2012 were $6.4 million, $6.0 million and $4.6 million, respectively.

We maintain a self-insurance program, for major medical and hospitalization coverage for employees and their dependents, which is partially funded by employee payroll deductions. We have provided for reported claims costs as well as incurred but not reported medical costs in the accompanying consolidated balance sheets. We have a maximum liability of $200,000 per covered individual per year. Amounts in excess of the stated maximum are covered under a separate policy provided by an insurance company. Accrued insurance premiums and deductibles at December 31, 2014 and 2013 include $3.4 million and $3.1 million, respectively, for our estimate of incurred but unpaid costs related to the self-insurance portion of our health insurance.

We are self-insured for up to $500,000 per incident for all workers' compensation claims submitted by employees for on-the-job injuries. We have a deductible of $250,000 per occurrence under both our general liability insurance and auto liability insurance. We accrue our workers' compensation claim cost estimates based on historical claims development data and we accrue the cost of administrative services associated with claims processing. Accrued insurance premiums and deductibles at December 31, 2014 and 2013 include $9.0 million and $7.3 million, respectively, for our estimate of costs relative to the self-insured portion of our workers' compensation, general liability and auto liability insurance. Based upon our past experience, management believes that we have adequately provided for potential losses. However, future multiple occurrences of serious injuries to employees could have a material adverse effect on our financial position and results of operations.

11. Segment Information

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

Drilling Services Segment—Our Drilling Services Segment provides contract land drilling services to a diverse group of oil and gas exploration and production companies through our six drilling divisions in the US and internationally in Colombia.

The following is a summary of our drilling rig counts as of December 31, 2014 and February 1, 2015.

	Drilling Rigs Owned	Drilling Rigs Held for Sale	Drilling Rig Fleet Count
As of December 31, 2014	62	(9)	53
As of February 1, 2015	59	(12)	47

As of February 1, 2015, the drilling rigs in our fleet are assigned to the following divisions:

Drilling Division	Rig Count
South Texas	13
West Texas	10
North Dakota	9
Utah	4
Appalachia	3
Colombia	8
	47

Production Services Segment—Our Production Services Segment provides a range of services to exploration and production companies, including well servicing, wireline services and coiled tubing services. Our production services operations are concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. As of February 1, 2015, we have a fleet of

117 well servicing rigs consisting of 107 rigs with 550 horsepower and 10 rigs with 600 horsepower. We provide wireline services and coiled tubing services with a fleet of 128 wireline units and 17 coiled tubing units. On September 17, 2014, we completed the disposition of our fishing and rental services operations.

The following tables set forth certain financial information for our two operating segments and corporate as of and for the years ending December 31, 2014, 2013 and 2012 (amounts in thousands):

	As of and for the year ended December 31, 2014			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$ 712,604	$ 412,516	$ 46,469	$ 1,171,589
Revenues	$ 516,473	$ 538,750	$ —	$ 1,055,223
Operating costs	345,862	340,102	—	685,964
Segment margin	$ 170,611	$ 198,648	$ —	$ 369,259
Depreciation and amortization	$ 115,714	$ 66,326	$ 1,336	$ 183,376
Capital expenditures	$ 112,483	$ 74,652	$ 986	$ 188,121

	As of and for the year ended December 31, 2013			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$ 791,820	$ 395,219	$ 42,584	$ 1,229,623
Revenues	$ 528,327	$ 431,859	$ —	$ 960,186
Operating costs	351,630	277,625	—	629,255
Segment margin	$ 176,697	$ 154,234	$ —	$ 330,931
Depreciation and amortization	$ 122,201	$ 64,604	$ 1,113	$ 187,918
Capital expenditures	$ 78,708	$ 44,541	$ 2,171	$ 125,420

	As of and for the year ended December 31, 2012			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$ 867,526	$ 439,113	$ 33,137	$ 1,339,776
Revenues	$ 498,867	$ 420,576	$ —	$ 919,443
Operating costs	333,846	252,775	—	586,621
Segment margin	$ 165,021	$ 167,801	$ —	$ 332,822
Depreciation and amortization	$ 108,151	$ 55,693	$ 873	$ 164,717
Capital expenditures	$ 265,966	$ 110,813	$ 2,493	$ 379,272

The following table reconciles the segment profits reported above to income from operations as reported on the consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012 (amounts in thousands):

	Year ended December 31,		
	2014	2013	2012
Segment margin	$ 369,259	$ 330,931	$ 332,822
Depreciation and amortization	(183,376)	(187,918)	(164,717)
General and administrative	(103,385)	(94,183)	(85,603)
Bad debt expense	(1,445)	(767)	440
Impairment charges	(73,025)	(54,292)	(1,131)
Gain on sale of fishing and rental services operations	10,702	—	—
Gain on litigation	5,254	—	—
Income (loss) from operations	$ 23,984	$ (6,229)	$ 81,811

The following table sets forth certain financial information for our international operations in Colombia as of and for the years ended December 31, 2014, 2013 and 2012 (amounts in thousands):

	As of and for the year ended December 31,		
	2014	2013	2012
Identifiable assets	$ 142,321	$ 150,719	$ 148,567
Revenues	$ 104,520	$ 115,631	$ 95,338

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.

12. 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 $51.7 million relating to our performance under these bonds as of December 31, 2014.

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.

13. Quarterly Results of Operations (unaudited)

The following table summarizes quarterly financial data for the years ended December 31, 2014 and 2013 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Year ended December 31, 2014					
Revenues	$ 239,034	$ 259,812	$ 273,267	$ 283,110	$1,055,223
Income (loss) from operations	17,935	21,917	32,804	(48,672)	23,984
Income tax (expense) benefit	(37)	1,070	(9,927)	20,198	11,304
Net income (loss)	(2,579)	(319)	12,453	(47,573)	(38,018)
Earnings (loss) per share:					
Basic	$ (0.04)	$ (0.01)	$ 0.20	$ (0.75)	$ (0.60)
Diluted	$ (0.04)	$ (0.01)	$ 0.19	$ (0.75)	$ (0.60)
Year ended December 31, 2013					
Revenues	$ 229,670	$ 248,354	$ 243,979	$ 238,183	$ 960,186
Income (loss) from operations	10,445	(27,268)	1,870	8,724	(6,229)
Income tax (expense) benefit	546	14,953	3,614	733	19,846
Net income (loss)	(1,292)	(25,895)	(6,230)	(2,515)	(35,932)
Earnings (loss) per share:					
Basic	$ (0.02)	$ (0.42)	$ (0.10)	$ (0.04)	$ (0.58)
Diluted	$ (0.02)	$ (0.42)	$ (0.10)	$ (0.04)	$ (0.58)

14. Subsequent Events

The following is a summary of our drilling rig counts as of December 31, 2014 and February 1, 2015.

	Drilling Rigs Owned	Drilling Rigs Held for Sale	Drilling Rig Fleet Count
As of December 31, 2014	62	(9)	53
As of February 1, 2015	59	(12)	47

In January, we sold three drilling rigs and placed an additional six drilling rigs as held for sale. In February, we sold another three drilling rigs and we expect to place an additional nine drilling rigs as held for sale before the end of the first quarter of 2015. Excluding the drilling rigs which we expect to sell, we expect to have 38 drilling rigs in our fleet at March 31, 2015.

The net book value of the nine drilling rigs held for sale at December 31, 2014 is $9.1 million, which is classified as current assets held for sale in our consolidated balance sheet. The net book value as of December 31, 2014 of the 15 additional rigs which we expect to place as held for sale during the first quarter of 2015 is $17.5 million.

In addition to the six drilling rigs which we sold in January and February 2015, we sold one real estate property, for a combined total of $17.8 million. We did not incur any additional loss upon the sale of these assets.

15. 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 December 31, 2014, 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)

	December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	27,688	(5,516)	12,752	—	$ 34,924
Receivables, net of allowance	1,641	151,048	37,512	—	190,201
Intercompany receivable (payable)	(24,836)	55,567	(30,728)	(3)	—
Deferred income taxes	1,827	8,196	975	—	10,998
Inventory	—	7,208	6,909	—	14,117
Assets held for sale	—	9,909	—	—	9,909
Prepaid expenses and other current assets	1,217	6,554	1,154	—	8,925
Total current assets	7,537	232,966	28,574	(3)	269,074
Net property and equipment	4,179	763,994	89,118	(750)	856,541
Investment in subsidiaries	830,185	116,799	—	(946,984)	—
Intangible assets, net of accumulated amortization	—	24,223	—	—	24,223
Noncurrent deferred income taxes	111,286	—	2,753	(111,286)	2,753
Other long-term assets	10,122	1,955	6,921	—	18,998
Total assets	$ 963,309	$ 1,139,937	$ 127,366	$ (1,059,023)	$ 1,171,589
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 735	$ 57,910	$ 5,660	—	$ 64,305
Current portion of long-term debt	—	27	—	—	27
Deferred revenues	—	3,315	—	—	3,315
Accrued expenses	11,109	64,063	4,376	(3)	79,545
Total current liabilities	11,844	125,315	10,036	(3)	147,192
Long-term debt, less current portion	455,000	53	—	—	455,053
Noncurrent deferred income taxes	138	180,726	—	(111,286)	69,578
Other long-term liabilities	513	3,658	531	—	4,702
Total liabilities	467,495	309,752	10,567	(111,289)	676,525
Total shareholders' equity	495,814	830,185	116,799	(947,734)	495,064
Total liabilities and shareholders' equity	$ 963,309	$ 1,139,937	$ 127,366	$ (1,059,023)	$ 1,171,589

	December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 28,368	$ (2,059)	$ 1,076	$ —	$ 27,385
Receivables, net of allowance	905	125,979	49,476	—	176,360
Intercompany receivable (payable)	(24,837)	52,671	(27,834)	—	—
Deferred income taxes	1,143	8,005	3,944	—	13,092
Inventory	—	7,415	5,817	—	13,232
Prepaid expenses and other current assets	1,013	7,094	1,204	—	9,311
Total current assets	6,592	199,105	33,683	—	239,380
Net property and equipment	4,531	846,632	87,244	(750)	937,657
Investment in subsidiaries	939,091	120,630	—	(1,059,721)	—
Intangible assets, net of accumulated amortization	—	32,194	—	—	32,194
Noncurrent deferred income taxes	78,486	—	1,156	(78,486)	1,156
Other long-term assets	7,588	2,009	9,639	—	19,236
Total assets	$ 1,036,288	$ 1,200,570	$ 131,722	$ (1,138,957)	$ 1,229,623
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 757	$ 37,797	$ 5,164	$ —	$ 43,718
Current portion of long-term debt	—	2,847	—	—	2,847
Deferred revenues	—	699	—	—	699
Accrued expenses	16,368	51,739	5,462	—	73,569
Total current liabilities	17,125	93,082	10,626	—	120,833
Long-term debt, less current portion	499,586	80	—	—	499,666
Noncurrent deferred income taxes	—	163,122	—	(78,486)	84,636
Other long-term liabilities	394	5,195	466	—	6,055
Total liabilities	517,105	261,479	11,092	(78,486)	711,190
Total shareholders' equity	519,183	939,091	120,630	(1,060,471)	518,433
Total liabilities and shareholders' equity	$ 1,036,288	$ 1,200,570	$ 131,722	$ (1,138,957)	$ 1,229,623

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	Year ended December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 950,703	$ 104,520	$ —	$ 1,055,223
Costs and expenses:					
Operating costs	—	609,596	76,368	—	685,964
Depreciation and amortization	1,336	168,157	13,883	—	183,376
General and administrative	27,314	72,878	3,745	(552)	103,385
Bad debt expense (recovery)	—	1,329	116	—	1,445
Impairment charges	—	73,025	—	—	73,025
Gain on sale of fishing and rental services operations	—	(10,702)	—	—	(10,702)
Gain on litigation	(5,254)	—	—	—	(5,254)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	23,396	909,423	98,972	(552)	1,031,239
Income (loss) from operations	(23,396)	41,280	5,548	552	23,984
Other (expense) income:					
Equity in earnings of subsidiaries	21,254	(3,767)	—	(17,487)	—
Interest expense, net of interest capitalized	(38,562)	(223)	4	—	(38,781)
Loss on extinguishment of debt	(31,221)	—	—	—	(31,221)
Other	21	2,985	(5,758)	(552)	(3,304)
Total other (expense) income	(48,508)	(1,005)	(5,754)	(18,039)	(73,306)
Income (loss) before income taxes	(71,904)	40,275	(206)	(17,487)	(49,322)
Income tax (expense) benefit	33,886	(19,021)	(3,561)	—	11,304
Net income (loss)	$ (38,018)	$ 21,254	$ (3,767)	$ (17,487)	$ (38,018)

	Year ended December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 844,555	$ 115,631	$ —	$ 960,186
Costs and expenses:					
Operating costs	—	548,345	80,910	—	629,255
Depreciation and amortization	1,113	173,516	13,289	—	187,918
General and administrative	25,272	65,962	3,501	(552)	94,183
Bad debt expense (recovery)	67	700	—	—	767
Impairment charges	—	54,292	—	—	54,292
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	26,452	837,955	102,560	(552)	966,415
Income (loss) from operations	(26,452)	6,600	13,071	552	(6,229)
Other (expense) income:					
Equity in earnings of subsidiaries	11,861	6,260	—	(18,121)	—
Interest expense, net of interest capitalized	(48,302)	(37)	29	—	(48,310)
Other	9	1,990	(2,686)	(552)	(1,239)
Total other (expense) income	(36,432)	8,213	(2,657)	(18,673)	(49,549)
Income (loss) before income taxes	(62,884)	14,813	10,414	(18,121)	(55,778)
Income tax (expense) benefit	26,952	(2,952)	(4,154)	—	19,846
Net income (loss)	$ (35,932)	$ 11,861	$ 6,260	$ (18,121)	$ (35,932)

	Year ended December 31, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 779,163	$ 140,280	$ —	$ 919,443
Costs and expenses:					
Operating costs	—	485,342	101,279	—	586,621
Depreciation and amortization	873	142,972	20,872	—	164,717
General and administrative	22,212	54,715	9,228	(552)	85,603
Bad debt expense (recovery)	—	(612)	172	—	(440)
Impairment of equipment	—	1,131	—	—	1,131
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	23,085	678,688	136,411	(552)	837,632
Income (loss) from operations	(23,085)	100,475	3,869	552	81,811
Other (expense) income:					
Equity in earnings of subsidiaries	68,352	4,029	—	(72,381)	—
Interest expense	(37,011)	(59)	21	—	(37,049)
Other	268	940	968	(552)	1,624
Total other (expense) income	31,609	4,910	989	(72,933)	(35,425)
Income (loss) before income taxes	8,524	105,385	4,858	(72,381)	46,386
Income tax expense (benefit)	21,508	(37,033)	(829)	—	(16,354)
Net income (loss)	$ 30,032	$ 68,352	$ 4,029	$ (72,381)	$ 30,032

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

	Year ended December 31, 2014			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$ 58,818	$ 146,891	$ 27,332	$ 233,041
Cash flows from investing activities:				
Purchases of property and equipment	(1,029)	(158,392)	(15,957)	(175,378)
Proceeds from sale of fishing and rental services operations	15,090	—	—	15,090
Proceeds from sale of property and equipment	—	8,069	301	8,370
	14,061	(150,323)	(15,656)	(151,918)
Cash flows from financing activities:				
Debt repayments	(490,000)	(25)	—	(490,025)
Proceeds from issuance of debt	440,000	—	—	440,000
Debt issuance costs	(9,239)	—	—	(9,239)
Tender premium costs	(21,553)	—	—	(21,553)
Proceeds from exercise of options	8,368	—	—	8,368
Purchase of treasury stock	(1,135)	—	—	(1,135)
	(73,559)	(25)	—	(73,584)
Net increase (decrease) in cash and cash equivalents	(680)	(3,457)	11,676	7,539
Beginning cash and cash equivalents	28,368	(2,059)	1,076	27,385
Ending cash and cash equivalents	$ 27,688	$ (5,516)	$ 12,752	$ 34,924

	Year ended December 31, 2013			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$ 31,908	$ 142,225	$ 447	$ 174,580
Cash flows from investing activities:				
Purchases of property and equipment	(2,649)	(151,363)	(11,344)	(165,356)
Proceeds from sale of property and equipment	8	12,510	1,318	13,836
Proceeds from insurance recoveries	—	844	—	844
	(2,641)	(138,009)	(10,026)	(150,676)
Cash flows from financing activities:				
Debt repayments	(60,000)	(874)	—	(60,874)
Proceeds from issuance of debt	40,000	—	—	40,000
Debt issuance costs	(13)	—	—	(13)
Proceeds from exercise of options	1,266	—	—	1,266
Purchase of treasury stock	(631)	—	—	(631)
	(19,378)	(874)	—	(20,252)
Net increase (decrease) in cash and cash equivalents	9,889	3,342	(9,579)	3,652
Beginning cash and cash equivalents	18,479	(5,401)	10,655	23,733
Ending cash and cash equivalents	$ 28,368	$ (2,059)	$ 1,076	$ 27,385

	Year ended December 31, 2012			
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities	$ (171,541)	$ 338,418	$ 32,489	$ 199,366
Cash flows from investing activities:				
Purchases of property and equipment	(2,187)	(332,082)	(30,055)	(364,324)
Proceeds from sale of property and equipment	—	2,998	95	3,093
	(2,187)	(329,084)	(29,960)	(361,231)
Cash flows from financing activities:				
Debt repayments	—	(856)	(18)	(874)
Proceeds from issuance of debt	100,000	—	—	100,000
Debt issuance costs	(58)	—	—	(58)
Proceeds from exercise of options	693	—	—	693
Purchase of treasury stock	(360)	—	—	(360)
	100,275	(856)	(18)	99,401
Net increase (decrease) in cash and cash equivalents	(73,453)	8,478	2,511	(62,464)
Beginning cash and cash equivalents	91,932	(13,879)	8,144	86,197
Ending cash and cash equivalents	$ 18,479	$ (5,401)	$ 10,655	$ 23,733

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. 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 December 31, 2014, to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management’s Annual Report on Internal Control Over Financial Reporting

The management of Pioneer Energy Services Corp. is responsible for establishing and maintaining adequate internal control over financial reporting. Pioneer Energy Services Corp.'s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Pioneer Energy Services Corp. are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pioneer Energy Services Corp.’s management assessed the effectiveness of Pioneer Energy Services Corp.’s internal control over financial reporting as of December 31, 2014. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (1992). Based on our assessment we have concluded that, as of December 31, 2014, Pioneer Energy Services Corp.’s internal control over financial reporting was effective based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of Pioneer Energy Services Corp. included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of Pioneer Energy Services Corp.’s internal control over financial reporting as of December 31, 2014. This report is included in Item 8, *Financial Statements and Supplementary Data*.

Item 9B. Other Information

Not applicable.

PART III

In Items 10, 11, 12, 13 and 14 below, we are incorporating by reference the information we refer to in those Items from the definitive proxy statement for our 2015 Annual Meeting of Shareholders. We intend to file that definitive proxy statement with the SEC on or about April 15, 2015.

Item 10. Directors, Executive Officers and Corporate Governance

Please see the information appearing in the proposal for the election of directors and under the headings "Executive Officers," "Information Concerning Meetings and Committees of the Board of Directors," "Code of Business Conduct and Ethics and Corporate Governance Guidelines" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the definitive proxy statement for our 2015 Annual Meeting of Shareholders for the information this Item 10 requires.

Item 11. Executive Compensation

Please see the information appearing under the headings "Compensation Discussion and Analysis," "Director Compensation," "Executive Compensation," "Compensation Committee Interlocks and Insider Participation" and "Report of the Compensation Committee" in the definitive proxy statement for our 2015 Annual Meeting of Shareholders for the information this Item 11 requires.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Please see the information appearing under the headings "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management" in the definitive proxy statement for our 2015 Annual Meeting of Shareholders for the information this Item 12 requires.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Please see the information appearing in the proposal for the election of directors and under the heading "Certain Relationships and Related Transactions" in the definitive proxy statement for our 2015 Annual Meeting of Shareholders for the information this Item 13 requires.

Item 14. Principal Accountant Fees and Services

Please see the information appearing in the proposal for the ratification of the appointment of our independent registered public accounting firm in the definitive proxy statement for our 2015 Annual Meeting of Shareholders for the information this Item 14 requires.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements.

See Index to Consolidated Financial Statements included in Item 8, *Financial Statements and Supplementary Data*.

(2) Financial Statement Schedules.

No financial statement schedules are submitted because either they are inapplicable or because the required information is included in the consolidated financial statements or notes thereto.

(3) Exhibits.

The following exhibits are filed as part of this report:

Exhibit Number		Description
3.1*	-	Restated Articles of Incorporation of Pioneer Energy Services Corp. (Form 8-K dated July 30, 2012 (File No. 1-8182, Exhibit 3.1)).
3.2*	-	Amended and Restated Bylaws of Pioneer Energy Services Corp. (Form 8-K dated July 30, 2012 (File No. 1-8182, Exhibit 3.2)).
4.1*	-	Form of Certificate representing Common Stock of Pioneer Energy Services Corp. (Form 10-Q dated August 7, 2012 (File No. 1-8182, Exhibit 4.1)).
4.2*	-	Indenture, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 12, 2010 (File No. 1-8182, Exhibit 4.1)).
4.3*	-	Registration Rights Agreement, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated March 12, 2010 (File No. 1-8182, Exhibit 4.2)).
4.4*	-	First Supplemental Indenture, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated November 21, 2011 (File No. 1-8182, Exhibit 4.2)).
4.5*	-	Registration Rights Agreement, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated November 21, 2011 (File No. 1-8182, Exhibit 4.3)).
4.6*	-	Second Supplemental Indenture, dated October 1, 2012, by and among Pioneer Coiled Tubing Services, LLC, Pioneer Energy Services Corp., the other subsidiary guarantors and Wells Fargo Bank, National Association, as trustee (Form 10-Q dated November 1, 2012 (File No. 1-8182, Exhibit 4.6)).
4.7*	-	Indenture, dated March 18, 2014, by and among Pioneer Energy Services Corp., the subsidiaries named as guarantors therein and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 18, 2014 (File No. 1-8182, Exhibit 4.1)).
4.8*	-	Registration Rights Agreement, dated March 18, 2014, by and among Pioneer Energy Services Corp., the subsidiaries named as guarantors therein and the initial purchasers party thereto (Form 8-K dated March 18, 2014 (File No. 1-8182, Exhibit 10.1)).
10.1+*	-	Pioneer Drilling Company's 1999 Stock Plan and Form of Stock Option Agreement (Form 10-K dated June 22, 2001 (File No. 1-8182, Exhibit 10.7)).
10.2+*	-	Pioneer Drilling Company 2003 Stock Plan (Form S-8 dated November 18, 2003 (File No. 333-110569, Exhibit 4.4)).

10.3+*	-	Pioneer Drilling Company Amended and Restated 2007 Incentive Plan (Form 10-Q dated November 3, 2011 (File No. 1-8182, Exhibit 10.1)).
10.4+*	-	Pioneer Drilling Company 2007 Incentive Plan Form of Employee Restricted Stock Award Agreement (Form 8-K dated September 4, 2008 (File No. 1-8182, Exhibit 10.2)).
10.5*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.2)).
10.6+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.3)).
10.7+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Restricted Stock Unit Award Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.4)).
10.8+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Restricted Stock Unit Award Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.5)).
10.9+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Non-Employee Director Restricted Stock Award Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.6)).
10.10+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Cash Award Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.7)).
10.11+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Cash Award Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.8)).
10.12+*	-	Pioneer Drilling Company Amended and Restated Key Executive Severance Plan (Form 10-Q for the dated August 5, 2008 (File No. 1-8182, Exhibit 10.4)).
10.13+*	-	Pioneer Drilling Company Form of Indemnification Agreement (Form 8-K dated August 8, 2007 (File No. 1-8182, Exhibit 10.1)).
10.14+*	-	Pioneer Drilling Company Employee Relocation Policy Executive Officers – Package A (Form 8-K dated August 8, 2007 (File No. 1-8182, Exhibit 10.3)).
10.15*	-	Amended and Restated Credit Agreement, dated as of June 30, 2011 among Pioneer Drilling Company, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent, issuing lender and swing line lender (Form 8-K dated July 5, 2011 (File No. 1-8182, Exhibit 10.1)).
10.16*	-	First Amendment dated as of March 3, 2014, by and among Pioneer Energy Services Corp. (f/k/a Pioneer Drilling Company), a Texas corporation, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated March 4, 2014 (File No. 1-8182, Exhibit 4.1)).
10.17*	-	Second Amendment dated as of September 22, 2014, by and among Pioneer Energy Services Corp. (f/k/a Pioneer Drilling Company), a Texas corporation, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated September 23, 2014 (File No. 1-8182, Exhibit 4.1)).
10.18+*	-	Employment Letter, effective March 1, 2008, from Pioneer Drilling Company to Joseph B. Eustace (Form 8-K dated March 5, 2008 (File No. 1-8182, Exhibit 10.1)).
10.19+*	-	Confidentiality and Non-Competition Agreement, dated February 29, 2008, by and between Pioneer Drilling Company, Pioneer Production Services, Inc. and Joe Eustace (Form 8-K dated March 5, 2008 (File No. 1-8182, Exhibit 10.2)).
10.20+*	-	Employment Letter, effective January 7, 2009, from Pioneer Drilling Company to Lorne E. Phillips (Form 8-K dated January 14, 2009 (File No. 1-8182, Exhibit 10.1)).
10.21+*	-	Pioneer Energy Services Corp. Nonqualified Retirement Savings and Investment Plan (Form 8-K dated January 30, 2013 (File No. 1-8182, Exhibit 10.1)).
10.22+*	-	Amended and Restated Pioneer Energy Services Corp. 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 12, 2013 (File No. 1-8182)).

10.23+*	-	Amended and Restated Pioneer Energy Services Corp. 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 9, 2014 (File No. 1-8182)).
10.24+**	-	Retirement and Consulting Services Agreement and Complete Release of All Claims, effective January 1, 2015, by and between Pioneer Energy Services Corp and F.C. "Red" West.
12.1**	-	Computation of ratio of earnings to fixed charges.
21.1**	-	Subsidiaries of Pioneer Energy Services Corp.
23.1**	-	Consent of Independent Registered Public Accounting Firm.
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-K for the year ended December 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Shareholders' Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

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*   Incorporated by reference to the filing indicated.

**   Filed herewith.

Furnished herewith.

+   Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

February 17, 2015

/S/ WM. STACY LOCKE
Wm. Stacy Locke
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/S/ DEAN A. BURKHARDT Dean A. Burkhardt	Chairman	February 17, 2015
/S/ WM. STACY LOCKE Wm. Stacy Locke	President, Chief Executive Officer and Director (Principal Executive Officer)	February 17, 2015
/S/ LORNE E. PHILLIPS Lorne E. Phillips	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 17, 2015
/S/ C. JOHN THOMPSON C. John Thompson	Director	February 17, 2015
/S/ JOHN MICHAEL RAUH John Michael Rauh	Director	February 17, 2015
/S/ SCOTT D. URBAN Scott D. Urban	Director	February 17, 2015

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PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
Reconciliation of Adjusted EBITDA to Net Income (Loss)
(in thousands)

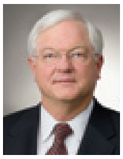
	Year ended December 31,				
	2014	2013	2012	2011	2010
Reconciliation of Adjusted EBITDA to net income (loss):					
Adjusted EBITDA*	$ 277,081	$ 234,742	$ 249,283	$ 183,870	$ 103,151
Depreciation and amortization	(183,376)	(187,918)	(164,717)	(132,832)	(120,811)
Impairment charges	(73,025)	(54,292)	(1,131)	(484)	(3,331)
Interest expense	(38,781)	(48,310)	(37,049)	(29,721)	(26,567)
Loss on extinguishment of debt	(31,221)	—	—	—	—
Income tax (expense) benefit	11,304	19,846	(16,354)	(9,656)	14,297
Net income (loss)	$ (38,018)	$ (35,932)	$ 30,032	$ 11,177	$ (33,261)

*Adjusted EBITDA represents income (loss) before interest income (expense), taxes, depreciation, amortization, loss on extinguishment of debt and impairments. We use this non-GAAP measure, together with our GAAP financial metrics, to assess our financial performance and evaluate our overall progress towards meeting our long-term financial objectives. We believe that this measure is useful to investors and analysts in allowing for greater transparency of our operating performance and makes it easier to compare our results with those of other companies within our industry. Adjusted EBITDA should not be considered (a) in isolation of, or as a substitute for, net income (loss), (b) as an indication of cash flows from operating activities or (c) as a measure of liquidity. In addition, Adjusted EBITDA does not represent funds available for discretionary use. Adjusted EBITDA may not be comparable to other similarly titled measures reported by other companies.

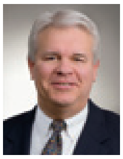
DIRECTORS

DEAN A. BURKHARDT
Consultant to energy industry

SCOTT D. URBAN
Partner in Edgewater Energy



JOHN MICHAEL RAUH
Retired
Kerr-McGee Corporation



C. JOHN THOMPSON
Chairman and Chief Executive Officer
Ventana Capital Advisors, Inc.

WM. STACY LOCKE
President and
Chief Executive Officer
Pioneer Energy Services Corp.

OFFICERS

WM. STACY LOCKE
President and
Chief Executive Officer

LORNE E. PHILLIPS
Executive Vice President and
Chief Financial Officer

BRIAN L. TUCKER
President of Drilling Services

CARLOS R. PEÑA
Senior Vice President,
General Counsel, Secretary and
Compliance Officer

BILL W. BOUZIDEN
Senior Vice President of Wireline
Services and Coiled Tubing Services

JOE P. FREEMAN
Senior Vice President
of Well Servicing

CORPORATE INFORMATION

CORPORATE HEADQUARTERS
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855.884.0575
Fax 210.828.8228

AUDITORS
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17802 IH-10, Suite 101
Promenade Two
San Antonio, Texas 78257

SHAREHOLDER CONTACT
Lorne E. Phillips
Executive Vice President and
Chief Financial Officer
855.884.0575
Fax 210.828.8228
investorrelations@pioneeres.com

A copy of the Company's annual report on Form 10-K is available, without charge, upon request to the address listed above.

STOCK LISTING
The New York Stock Exchange: PES

As of March 23, 2015, the approximate number of common shareholders of record was 356.

INVESTOR RELATIONS
Lisa Elliott
Dennard ▪ Lascar Associates
713.529.6600
lelliott@DennardLascar.com

Anne Pearson
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210.408.6321
apearson@DennardLascar.com

Certain information in this Annual Report, including information related to the retirement of our indebtedness, our future revenue stream, our future investment focus, future market conditions, future oil and gas prices, fleet size, rig utilization, pricing, length of the current industry downturn, drilling contracts, and hourly rates, as well as other statements that express a belief, expectation or intention, and those that are not statements of historical fact, are forward-looking statements. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "plan, "intend," "seek," "will," "should," "goal" or other words and phrases of similar import that convey the uncertainty of future events or outcomes. These forward-looking statements speak only as of the date of the preparation of this Annual Report. We disclaim any obligation to update any of these forward-looking statements, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties include, among other matters, the risks set forth in Item 1A—"Risk Factors" of our Form 10-K for the fiscal year ended December 31, 2014. These risks, contingencies and uncertainties could cause our actual results to differ materially from those expressed in a forward-looking statement contained in this Annual Report. Unpredictable or unknown factors we have not discussed in this Annual Report or elsewhere could also have material adverse effects on actual results of matters that are the subject of our forward-looking statements. We advise our shareholders to (1) be aware that important factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements.

Pioneer Energy Services
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