March 27, 2015

Dear Shareholders,

I am pleased to update you on our progress in 2014 and our journey of continual improvement. We made measurable headway on a number of our strategic goals - raising international drilling utilization, expanding our operations and maintenance (O&M) footprint, enhancing the company's financial condition and investing in future growth. However, this progress was slowed by steeply declining oil prices in the latter part of the year, and key areas of our international business were impacted by regulatory reforms and geopolitical events.

On the international drilling front, we raised our average utilization to 70% in 2014 from 60% in 2013, with 18 of our 22 international rigs under contract at the end of the year. We secured four drilling contracts in the fourth quarter alone, with operations on those contracts scheduled to begin in the first quarter of 2015. I'm pleased to report two of those four contracts put long idle rigs back to work. This has been a key focus area for the company. We also sold two older rigs that no longer align with our strategy.

Our record of achievement in extended reach drilling operations helped us expand our footprint in O&M work with the addition of two new projects - one on Sakhalin Island, Russia and another in the growing Middle East market. These O&M projects are perfectly aligned with the expertise we've cultivated over 80 years of operations. We believe we add meaningful value for our customers and for Parker through these types of projects and we will continue to seek out these opportunities throughout our drilling business.

In our barge drilling business, we raised our average dayrates by 16% in 2014, despite the impacts of the downturn in the latter part of the year. The additions of Rig 55B and Rig 30B in the spring brought new features and increased capabilities to our already diverse barge rig fleet. I'm also pleased that our crews on Rig 8B received a perfect score on a recent customer performance survey - a solid indication that our efforts to align with our customers are succeeding. In addition, our Arctic-class drilling rigs and dedicated crews in Alaska consistently delivered strong operational performance for our customers in 2014. Their efforts to continually improve and increase efficiencies resulted in solid financial gains for our U.S. drilling business during the year.

Our combined drilling operations, including both U.S. and international operations as well as our O&M projects, ended the year with an estimated revenue backlog of approximately $670 million.

In Rental Tools, the utilization index for our U.S. rental tools tubular goods rose in the fourth quarter to its highest level of the year. As a result, the index average was 91 for 2014 compared with 80 for 2013. We made substantial investments in our deepwater Gulf of Mexico business during the year and, consequently, our fourth quarter revenues from this business grew significantly year-over-year.

Our international rental tools business successfully navigated through market disruptions in key areas during the year. In spite of these challenges, the business benefited from growth in the Middle East, Europe and Latin America and achieved its highest quarterly revenues and gross margins in the fourth quarter. We are confident this area of our business will continue to make meaningful contributions by providing timely and cost effective rental tools products and well services where and when our customers need them.

We further strengthened our financial position during the year. We reduced our debt by approximately $39 million and refinanced $360 million of debt at lower interest rates and with extended maturities. In January 2015, we amended our revolving credit facility, expanding it to $200 million and extending its maturity to 2020, providing greater liquidity and financial flexibility.

The year, however, was not without its challenges. Geopolitical events in Iraq limited market growth, which hampered our ability to expand our rig fleet and grow our international rental tools business in the Middle East. The complications of regulatory reform slowed drilling activity in Mexico and Colombia and this delayed some of the growth we expected in our contract drilling and rental tools portfolios in those two countries. In addition, the steep drop in global oil prices began to reverse the momentum we were building in our U.S. barge drilling business and slowed the growth of our U.S. rental tools business.

The sharp decline in oil prices has already triggered substantial changes in U.S. drilling activity and we're beginning to see the impact spread to international markets, as well. Market conditions and expectations are changing rapidly and no one can anticipate the depth or the duration of this downturn. There is no doubt 2015 will be a tough year and we are positioning our operations as if this slowdown will be with us for a while.

For example, we've taken actions throughout the company to lower our costs, maintain our utilization levels, manage our cash and liquidity, and preserve our ability to selectively and effectively respond to market opportunities as conditions improve. Some of this work has forced us to make tough decisions that affect our team members directly. We have asked much of our employees in the past few years to help us strengthen our ability to bring reliable results to our customers and they've consistently delivered. As a team, we felt our momentum growing during the year which makes this downturn, and these choices, even more difficult. As leaders, making these tough choices is the hardest part of our job, but we are doing so in order to maintain our business for the long-term.

And we are here for the long-term. I'd like to point out that Parker was founded 80 years ago in the middle of the Great Depression. Throughout our journey, we've weathered many storms and I'm confident we'll weather this market recession too. For generations, we've been the company our customers trust to help them safely manage their costs and mitigate their risks. It's what we do best and our customers need this determination and expertise now more than ever. In 2015, our relentless focus on their needs and our work to improve our operational execution will ensure we continue to deliver **innovative**, **reliable** and **efficient** performance during this downturn and as market conditions improve.

I look forward to reporting to you again next year,

Gary G. Rich
Chairman, President & Chief Executive Officer

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**

FOR THE TRANSITION PERIOD FROM TO

COMMISSION FILE NUMBER 1-7573

PARKER DRILLING COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**73-0618660**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5 Greenway Plaza, Suite 100, Houston, Texas	**77046**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:
(281) 406-2000

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered:
Common Stock, par value $0.16\ ^2/_3$ per share	New York Stock Exchange

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 Exchange 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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ 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 Act). Yes ☐ No ☑

The aggregate market value of our common stock held by non-affiliates on June 30, 2014 was $770.3 million. At February 23, 2015, there were 122,047,336 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our definitive proxy statement for the Annual Meeting of Shareholders to be held on May 7, 2015 are incorporated by reference in Part III.

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PART I

Item 1. Business

General

Unless otherwise indicated, the terms “Company,” “Parker,” “we,” “us” and “our” refer to Parker Drilling Company together with its subsidiaries and "Parker Drilling" refers solely to the parent, Parker Drilling Company. Parker Drilling was incorporated in the state of Oklahoma in 1954 after having been established in 1934. In March 1976, the state of incorporation of the Company was changed to Delaware. Our principal executive offices are located at 5 Greenway Plaza, Suite 100, Houston, Texas 77046.

We are an international provider of contract drilling and drilling-related services and rental tools. We have operated in over 50 countries since beginning operations in 1934, making us among the most geographically experienced drilling contractors and rental tools providers in the world. We currently have operations in 23 countries. We own and operate drilling rigs and drilling-related equipment and also perform drilling-related services, referred to as operations and maintenance (O&M) services, for customer-owned drilling rigs on a contracted basis. We have extensive experience and expertise in drilling geologically difficult wells and in managing the logistical and technological challenges of operating in remote, harsh and ecologically sensitive areas. Our rental tools business supplies premium equipment to exploration and production (E&P) companies, drilling contractors and service companies on land and offshore in the United States (U.S.) and select international markets. We believe we are an industry leader in quality, health, safety and environmental practices.

Our business is currently comprised of five reportable segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, and Technical Services. For information regarding our reportable segments and operations by geographic areas for the years ended December 31, 2014, 2013 and 2012, see Note 12 - Reportable Segments in Item 8. Financial Statements and Supplementary Data and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Our Rental Tools Business

Our rental tools business provides premium rental tools and services for land and offshore oil and natural gas drilling, workover and production applications. Tools we provide include drill collars, standard and heavy-weight drill pipe, all of which are available with standard or high-torque connections, tubing, and pressure control equipment including blow-out preventers (BOPs). We also provide services including fishing, tubular running, inspection and machine shop support. Our U.S. rental tools business is headquartered in New Iberia, Louisiana and our international rental tools business is headquartered in Dubai, United Arab Emirates (UAE). We maintain an inventory of rental tools and provide services to our customers on land and offshore from facilities in Louisiana, Texas, Oklahoma, Wyoming, North Dakota, West Virginia, as well as in the Middle East, Latin America, U.K., Europe, and Asia-Pacific regions.

Our largest single market for rental tools is U.S. land drilling, a cyclical market driven primarily by oil and gas prices and our customers' access to project financing. A growing portion of our U.S. rental tools business is supplying tubular goods and other equipment to offshore Gulf of Mexico (GOM) customers.

Our principal customers are major and independent E&P companies. Generally, rental tools are used for only a portion of a well drilling program and are requested by the customer when they are needed, requiring us to keep a broad inventory of rental tools in stock. Rental tools are usually rented on a daily or monthly basis.

On April 22, 2013, we completed the acquisition of International Tubular Services Limited (ITS) and related assets (collectively, the ITS acquisition). See Note 2 — Acquisition of ITS in Item 8. Financial Statements and Supplementary Data for further discussion.

Our U.S. Barge Drilling Business

Our U.S. GOM barge drilling rig fleet is the largest marketed barge fleet in the GOM region, with rigs ranging from 1,000 to 3,000 horsepower with drilling depth capabilities ranging from 13,000 to over 30,000 feet. Our rigs drill for oil and natural gas in shallow waters in and along the inland waterways and coasts of Louisiana, Alabama and Texas. The majority of these wells are drilled in water depths of 6 to 12 feet. Our rigs are all equipped for zero-discharge operations and are suitable for a variety of drilling programs in inland coastal waters, from along inland waterways requiring shallow draft barges to open water drilling on the continental shelf requiring more robust capabilities. The barge drilling industry in the GOM is characterized by cyclical activity where utilization and dayrates are typically driven by oil and gas prices and our customers’ access to project financing. Contract terms tend to be well-to-well or multi-well programs, most commonly ranging from 45 to 150 days.

We continue to make investments in our barge drilling fleet to increase its efficiency and safety performance. In the second quarter of 2014 we completed the reconstruction of Rig 55B and acquired a 1,500 horsepower posted barge rig for our GOM drilling fleet.

Our U.S. Drilling Business

Our U.S. drilling business primarily consists of two arctic-class drilling rigs in Alaska designed to address the challenges presented by the remote location, harsh climate and sensitive environment that characterize the Alaskan North Slope, in addition to O&M work in support of a customer's offshore platform operations located in the Channel Islands region of California.

Our International Drilling Business

Our international drilling business includes operations related to Parker-owned and customer-owned rigs. We strive to deploy our fleet of Parker-owned rigs in markets where we expect to have opportunities to keep the rigs consistently utilized and build a sufficient presence to achieve efficient operating scale. We provide O&M and other project management services, such as labor, maintenance, technical and logistics support for operators who own their own drilling rigs, but choose Parker Drilling to operate the rigs for them. During the year ended December 31, 2014 we had rigs operating in Mexico, Colombia, Kazakhstan, Papua New Guinea, Indonesia, the Kurdistan Region of Iraq and Sakhalin Island, Russia. In addition, we have O&M and ongoing project management activities for customer-owned rigs in Abu Dhabi, Sakhalin Island, Russia and Kuwait.

The international drilling markets in which we operate have one or more of the following characteristics:

- customers that typically are major, independent or national oil and natural gas companies or integrated service providers;
- drilling programs in remote locations with little infrastructure requiring a large inventory of spare parts and other ancillary equipment and self-supported service capabilities;
- complex wells and/or harsh environments (such as high pressure, deep depths, hazardous or geologically challenging conditions) requiring specialized equipment and considerable experience to drill;
- drilling contracts that generally cover periods of one year or more; and
- O&M contracts that are typically in support of multi-year drilling programs.

Our Technical Services Business

Our technical services business includes engineering and related project services during concept development, pre-FEED (Front End Engineering Design) and FEED phases of customer-owned drilling facility projects. During the engineering, procurement, construction, installation and commissioning phases of these projects, we provide project management and procurement services focusing primarily on drilling equipment and drilling systems. As these projects are customer-owned and customer-funded, the technical services business does not typically require significant capital and we believe this business helps to position us for future expansion in the drilling O&M business.

Our technical services business is also our engineering expertise center and provides our ongoing businesses with services similar to those provided to our external customers, including rig design and management of repairs, modifications and upgrades to our existing rig fleet.

Our Business Strategy

We intend to successfully compete in select energy services businesses which benefit our customers' exploration, appraisal and development programs, and in which operational execution is the key measure of success. We will do this by:

- Consistently delivering innovative, reliable, and efficient results that help our customers reduce their operational risks and manage their operating costs; and
- Investing to improve and grow our existing business lines, and to expand the scope of products and services we offer.

Our Core Competencies

We believe our core competencies are the foundation for delivering operational excellence to our customers. Applying and strengthening these core competencies will be a key factor in our success:

Customer-aligned operational excellence: Our daily focus is meeting the needs of our customers. We strive to anticipate our customers' challenges and provide innovative, reliable and efficient solutions to help them achieve their business objectives.

Rapid Personnel Development: Motivated, skilled and effective people are critical to the successful execution of our strategy. We strive to attract and retain the best people, to develop depth and strength in key skills, and to provide a safety-and solutions-oriented workforce to our customers.

Selective and Effective Market Entry: We are selective about the services we provide, geographies in which we operate, and customers we serve. We intend to build Parker's business in markets with the best potential for sustained growth, profitability and operating scale. We are strategic, timely and intentional when we enter new markets and when we grow organically or through acquisition or investments in new business ventures.

Enhanced Asset Management and Predictive Maintenance: We believe well-maintained rigs, equipment and rental tools are critical to providing reliable results for our customers. We employ predictive and preventive maintenance programs and training to sustain high levels of effective utilization and to provide reliable operating performance and efficiency.

Standard, Modular and Configurable Processes and Equipment: To address the challenging and harsh environments in which our customers operate, we develop standardized processes and equipment that can be configured to meet each project's distinct technological requirements. Repeatable processes and modular equipment leverage our investments in assets and employees, increase efficiency and reduce disruption.

We believe there are tangible rewards from delivering value to our customers through superior execution of our core competencies. When we deliver innovative, reliable and efficient solutions aligned with our customers' needs, we believe we are well-positioned to earn premium rates, generate follow-on business and create growth opportunities that enhance our financial performance and advance our strategy.

Customers and Scope of Operations

Our customer base consists of major, independent and national oil and natural gas E&P companies and integrated service providers. Each of our segments depends on a limited number of key customers and the loss of any one or more key customers could have a material adverse effect on a segment. In 2014, our largest customer, Exxon Neftegas Limited accounted for approximately 18.7 percent of our total revenues. For information regarding our reportable segments and operations by geographic areas for the years ended December 31, 2014, 2013 and 2012, see Note 12 - Reportable Segments in Item 8. Financial Statements and Supplementary Data and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Competition

We operate in competitive businesses characterized by high capital requirements, rigorous technological challenges, evolving regulatory requirements and challenges in securing and retaining qualified field personnel.

In rental tools markets, we compete with suppliers both larger and smaller than our own business, some of which are components of larger enterprises. We compete against other rental tools companies based on breadth of inventory, the availability and price of product and quality of service. In the U.S. market, our network of locations provides broad and efficient product availability. In international markets, some business is obtained in conjunction with our drilling and O&M projects.

In drilling markets, most contracts are awarded on a competitive bidding basis and operators often consider reliability, efficiency and safety in addition to price. We have been successful in differentiating ourselves from competitors through our drilling performance and safety record, providing services that help our customers manage their operating costs and mitigate their operational risks.

In international drilling markets, we compete with a number of international drilling contractors as well as local contractors. Although local drilling contractors often have lower labor and mobilization costs, we are generally able to distinguish ourselves from these companies based on our technical expertise, safety performance, quality of service, and experience. We believe our expertise in operating in challenging environments has been a significant factor in securing contracts. In the GOM barge drilling market, we compete with a small number of contractors. We have the largest number and greatest diversity of rigs available in the market, allowing us to provide equipment and services that are well-matched to customers' requirements. We believe the market for drilling contracts will continue to be competitive with continued focus on reliability, efficiency and safety, in addition to price.

Contracts

Rental tools contracts are typically on a dayrate basis with rates determined based on type of equipment and competitive conditions. Rental rates generally apply from the time the equipment leaves our facility until it is returned. Rental contracts generally require the customer to pay for lost-in-hole or damaged equipment.

Most drilling contracts are awarded based on competitive bidding. The rates specified in drilling contracts vary depending upon the type of rig employed, equipment and services supplied, geographic location, term of the contract, competitive conditions and other variables. Our contracts generally provide for an operating dayrate during drilling operations, with lower rates for periods of equipment downtime, customer stoppage, adverse weather or other conditions, and no payment when certain conditions continue beyond contractually established parameters. When a rig mobilizes to or demobilizes from an operating area, the contract typically provides for a different dayrate or specified fixed payments during mobilization or demobilization. The terms of most of our contracts are based on either a specified period of time or the time required to drill a specified number of wells. The contract term in some instances may be extended by the customer exercising options for an additional time period or for the drilling of additional wells, or by exercising a right of first refusal. Most of our contracts allow termination by the customer prior to the end of the term without penalty under certain circumstances, such as the loss of or major damage to the drilling unit or other events that cause the suspension of drilling operations beyond a specified period of time. Certain contracts require the customer to pay an early termination fee if the customer terminates a contract before the end of the term without cause.

Technical services contracts include engineering, consulting, and project management scopes of work and are typically on a time and materials basis.

Seasonality

Our rigs in the inland waters of the GOM are subject to severe weather during certain periods of the year, particularly during hurricane season from June through November, which could halt operations for prolonged periods or limit contract opportunities during that period. In addition, mobilization, demobilization, or well-to-well movements of rigs in arctic regions can be affected by seasonal changes in weather or weather so severe the conditions are deemed too unsafe to operate.

Insurance and Indemnification

Substantially all of our operations are subject to hazards that are customary for oil and natural gas drilling operations, including blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, oil and natural gas well fires and explosions, natural disasters, pollution, mechanical failure and damage or loss during transportation. Some of our fleet is also subject to hazards inherent in marine operations, either while on-site or during mobilization, such as capsizing, sinking, grounding, collision, damage from severe weather and marine life infestations. These hazards could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. We have had accidents in the past due to some of these hazards.

Our contracts provide for varying levels of indemnification between ourselves and our customers, including with respect to well control and subsurface risks. We also maintain insurance for personal injuries, damage to or loss of equipment and other insurance coverage for various business risks. Our insurance policies are typically 12-month policy periods.

Our insurance program provides coverage, to the extent not otherwise paid by the customer under the indemnification provisions of the drilling or rental tool contract, for liability due to well control events and liability arising from third-party claims, including wrongful death and other personal injury claims by our personnel as well as claims brought on behalf of individuals who are not our employees. Generally, our program provides liability coverage up to $350.0 million, with retentions of $1.0 million or less.

Well control events generally include an unintended flow from the well that cannot be contained by using equipment on site (*e.g.,* a BOP), by increasing the weight of drilling fluid or by diverting the fluids safely into production. Our insurance program provides coverage for third-party liability claims relating to sudden and accidental pollution from a well control event up to $350.0 million per occurrence. A separate limit of $10.0 million exists to cover the costs of re-drilling of the well and well control costs under a Contingent Operators Extra Expense policy. For our rig based operations, remediation plans are in place to prevent the spread of pollutants and our insurance program provides coverage for removal, response and remedial actions. We retain the risk for liability not indemnified by the customer below the retention and in excess of our insurance coverage.

Based upon a risk assessment and due to the high cost, high self-insured retention and limited coverage for windstorms in the GOM, we have elected not to purchase windstorm insurance for our barge rigs in the GOM. Although we have retained the risk for physical loss or damage for these rigs arising from a named windstorm, we have procured insurance coverage for removal of a wreck caused by a windstorm.

Our contracts provide for varying levels of indemnification from our customers and may require us to indemnify our customers. Liability with respect to personnel and property is customarily assigned on a "knock-for-knock" basis, which means that we and our customers customarily assume liability for our respective personnel and property regardless of fault. In addition, our customers typically indemnify us for damage to our equipment down-hole, and in some cases our subsea equipment, generally based on replacement cost minus some level of depreciation. However, in certain contracts we may assume liability for damage to our customer's property and other third-party property on the rig and in other contracts we are not indemnified by our customers for damage to their property and, accordingly, could be liable for any such damage under applicable law.

Our customers typically assume responsibility for and indemnify us from any loss or liability resulting from pollution, including clean-up and removal and third-party damages, arising from operations under the contract and originating below the surface of the land or water, including losses or liability resulting from blowouts or cratering of the well. In some contracts, however, we may have liability for damages resulting from such pollution or contamination caused by our gross negligence or, in some cases, ordinary negligence.

We generally indemnify the customer for legal and financial consequences of spills of industrial waste, lubricants, solvents and other contaminants (other than drilling fluid) on the surface of the land or water originating from our rigs or equipment. We typically require our customers to retain liability for spills of drilling fluid (sometimes called "mud") which circulates down-hole to the drill bit, lubricates the bit and washes debris back to the surface. Drilling fluid often contains a mixture of synthetics, the exact composition of which is prescribed by the customer based on the particular geology of the well being drilled.

The above description of our insurance program and the indemnification provisions typically found in our contracts is only a summary as of the date hereof and is general in nature. Our insurance program and the terms of our drilling and rental tool contracts may change in the future. In addition, the indemnification provisions of our contracts may be subject to differing interpretations, and enforcement of those provisions may be limited by public policy and other considerations.

If any of the aforementioned operating hazards results in substantial liability and our insurance and contractual indemnification provisions are unavailable or insufficient, our financial condition, operating results or cash flows may be materially adversely affected.

Employees

The following table sets forth the composition of our employee base:

	December 31,	
	2014	2013
Rental Tools	1,110	1,122
U.S. Barge Drilling	470	444
U.S. Drilling	223	278
International Drilling	1,370	1,291
Technical Services and Corporate	270	260
Total employees	3,443	3,395

Environmental Considerations

Our operations are subject to numerous U.S. federal, state, and local laws and regulations, as well as the laws and regulations of other jurisdictions in which we operate, pertaining to the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations to implement and enforce laws pertaining to the environment, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities; limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas; require remedial action to clean up pollution from former operations; and impose substantial liabilities for pollution resulting from our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly compliance could adversely affect our operations and financial position, as well as those of similarly situated entities operating in the same markets. While our management believes that we comply with current applicable environmental laws and regulations, there is no assurance that compliance can be maintained in the future.

As an owner or operator of both onshore and offshore facilities, including mobile offshore drilling rigs in or near waters of the United States, we may be liable for the costs of clean up and damages arising out of a pollution incident to the extent set forth in federal statutes such as the Federal Water Pollution Control Act (commonly known as the Clean Water Act (CWA)), as amended by the Oil Pollution Act of 1990 (OPA); the Clean Air Act (CAA); the Outer Continental Shelf Lands Act (OCSLA); the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA); the Resource Conservation and Recovery Act (RCRA); the Emergency Planning and Community Right to Know Act (EPCRA); and the Hazardous Materials Transportation Act (HMTA) as well as comparable state laws. In addition, we may also be subject to civil claims arising out of any such incident.

The OPA and related regulations impose a variety of regulations on "responsible parties" related to the prevention of spills of oil or other hazardous substances and liability for damages resulting from such spills. "Responsible parties" include the owner or operator of a vessel, pipeline or onshore facility, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability for oil removal costs and a variety of public and private damages to each responsible party. The OPA also requires some facilities to demonstrate proof of financial responsibility and to prepare an oil spill response plan. Failure to comply with ongoing requirements or inadequate cooperation in a spill may subject a responsible party to civil or criminal enforcement actions.

The OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. The Bureau of Safety and Environmental Enforcement (BSEE) regulates the design and operation of well control and other equipment at offshore production sites, implementation of safety and environmental management systems, and mandatory third-party compliance audits, among other requirements. Violations of environmentally related lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities, delay or restriction of activities can result from either governmental or citizen prosecution.

Our operations are also governed by laws and regulations related to workplace safety and worker health, primarily the Occupational Safety and Health Act and regulations promulgated thereunder. In addition, various other governmental and quasi-governmental agencies require us to obtain certain miscellaneous permits, licenses and certificates with respect to our operations. The kind of permits, licenses and certificates required by our operations depend upon a number of factors. We believe we have the necessary permits, licenses and certificates that are material to the conduct of our existing business.

CERCLA (also known as "Superfund") and comparable state laws impose potential liability without regard to fault or the legality of the activity, on certain classes of persons who are considered to be responsible for the release of "hazardous substances" into the environment. While CERCLA exempts crude oil from the definition of hazardous substances for purposes of the statute, our operations may involve the use or handling of other materials that may be classified as hazardous substances. CERCLA assigns strict liability to a broad class of potentially responsible parties for all response and remediation costs, as well as natural resource damages. In addition, persons responsible for release of hazardous substances under CERCLA may be subject to joint and several liability for the cost of cleaning up the hazardous substances released into the environment and for damages to natural resources.

RCRA and comparable state laws regulate the management and disposal of solid and hazardous wastes. Current RCRA regulations specifically exclude from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, these wastes and other wastes may be otherwise regulated by EPA or state agencies. Moreover, ordinary industrial wastes, such as paint wastes, spent solvents, laboratory wastes, and used oils, may be regulated as hazardous waste. Although the costs of managing solid and hazardous wastes may be significant, we do not expect to experience more burdensome costs than competitor companies involved in similar drilling operations.

The CAA and similar state laws and regulations restrict the emission of air pollutants and may also impose various monitoring and reporting requirements. In addition, those laws may require us to obtain permits for the construction, modification, or operation of certain projects or facilities and the utilization of specific equipment or technologies to control emissions. For example, the EPA has adopted regulations known as "RICE MACT" that require the use of "maximum achievable control technology" to reduce formaldehyde and other emissions from certain stationary reciprocating internal combustion engines, which can include portable engines used to power drilling rigs.

Some scientific studies have suggested that emissions of certain gases including carbon dioxide and methane, commonly referred to as "greenhouse gases" (GHGs), may be contributing to the warming of the atmosphere resulting in climate change. There are a variety of legislative and regulatory developments, proposals, requirements, and initiatives that have been introduced in the U.S. and international regions in which we operate that are intended to address concerns that emissions of GHGs are contributing to climate change and these may increase costs of compliance for our drilling services or our customer's operations. Among these developments, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change established a set of emission targets for GHGs that became binding on all those countries that had ratified it.

Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws, regulations, treaties or international agreements related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business. In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our rigs, impact our ability to conduct our operations and result in a disruption of our customers' operations.

Executive Officers

Officers are elected each year by the board of directors following the annual shareholders' meeting for a term of one year or until the election and qualification of their successors. The current executive officers of the Company and their ages, positions with the Company and business experience are presented below:

- *Gary G. Rich, 56,* joined the Company in October 2012 as the president and chief executive officer. Mr. Rich also serves as Chairman of the Company's board of directors. He is an industry veteran with over 30 years of global technical, commercial and operations experience. Mr. Rich came to Parker Drilling after a 25-year career with Baker Hughes Incorporated. Mr. Rich served as vice president of global sales for Baker Hughes from August 2011 to October 2012, and prior to that role, he served as president of that company's European operations from April 2009 to August 2011. Previously, Mr. Rich was president of Hughes Christensen Company (HCC), a division of Baker Hughes primarily focused on the production and distribution of drilling bits for the petroleum industry.
- *Christopher T. Weber, 42,* joined the Company in May 2013 as the senior vice president and chief financial officer. Prior to joining the Company, Mr. Weber served as the vice president and treasurer of Ensco plc., a public offshore drilling company, from 2011 to May 2013. From 2009 to 2011, Mr. Weber served as vice president, operations for Pride International, Inc., prior to which he served as director, corporate planning and development from 2006 to 2009.
- *Jon-Al Duplantier, 47,* is the senior vice president, chief administrative officer, general counsel, and secretary of the Company, a position held since 2013. Mr. Duplantier has over 19 years' experience in the oil and gas industry. Mr. Duplantier joined the Company in 2009 as vice president and general counsel. From 1995 to 2009, Mr. Duplantier served in several legal and business roles at ConocoPhillips, including senior counsel – Exploration and Production, vice president and general counsel – Conoco Phillips Indonesia, and vice president and general counsel – Dubai Petroleum Company. Prior to joining ConocoPhillips, he served as a patent attorney for DuPont from 1992 to 1995.
- *David R. Farmer, 53,* was appointed the senior vice president, Europe, Middle East, and Asia (EMEA) in early 2014. He joined the Company in 2011 as vice president of operations. Mr. Farmer has over 20 years' experience in the upstream oilfield services business working in executive, engineering, operational, marketing, account management, planning, and general management roles in Europe, the Middle East, North America and South America. From 1991 to 2011, Mr. Farmer served in various positions at Schlumberger, including vice president and global account director – Schlumberger Ltd. The Netherlands, vice president and general manager – Schlumberger Oilfield Service Qatar, global marketing manager – Schlumberger Drilling & Measurement Division, Houston, Texas. Most recently, Mr. Farmer was responsible for Demand Planning management and the development of long term tactical resource plans for Schlumberger's Drilling & Measurement division.
- *Philip L. Agnew, 46,* has served as the Company's senior vice president and chief technical officer since 2013. He joined the Company in December 2010 as vice president of technical services. Mr. Agnew has more than 20 years' experience in design, construction and project management. From 2003 to 2010, Mr. Agnew held the position of President at Aker MH, Inc., a business unit of Aker Solutions AS. From 1998 to 2003, Mr. Agnew served as Project Manager and then vice president – Project Development at Signal International (previously Friede Goldman Offshore; TDI-Halter LP; Texas Drydock, Inc.). Prior to his career at Signal International, Mr. Agnew served a variety of leadership roles at Schlumberger Sedco Forex International Resources, Interface Consulting International, Inc., and Brown & Root, Inc.

Other Parker Drilling Company Officers

- *Leslie K. Nagy, 40,* was appointed principal accounting officer and controller on April 1, 2014. Ms. Nagy served as director of finance and assistant controller of the Company from December 2012 through March 2014, as assistant controller of the Company from May 2011 to December 2012, and as manager of external reporting and general accounting of the Company from August 2010 to May 2011. Prior to joining Parker Drilling, Mrs. Nagy worked for Ernst & Young LLP from 1997 to 2010.
- *Philip A. Schlom, 50,* was named vice president, global compliance and internal audit, effective December 2014. He joined the Company in 2009 as principal accounting officer and corporate controller. From 2008 to 2009, he held the position of vice president and corporate controller for Shared Technologies Inc. From 1997 to 2008, Mr. Schlom held several senior financial positions at Flowserve Corporation, a leading manufacturer of pumps, valves and seals for the energy sector. From 1988 through 1997, Mr. Schlom worked at the public accounting firm PricewaterhouseCoopers.
- *David W. Tucker, 59,* treasurer, joined the Company in 1978 as a financial analyst and served in various financial and accounting positions before being named chief financial officer of our formerly wholly-owned subsidiary, Hercules Offshore Corporation, in February 1998. Mr. Tucker was named treasurer of the Company in 1999.

Available Information

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 made available free of charge on our website at http://www.parkerdrilling.com as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission (SEC). The public may read and copy any materials we have filed with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. Additionally, our reports, proxy and information statements and our other SEC filings are available on an Internet website maintained by the SEC at http://www.sec.gov.

Item 1A. Risk Factors

Our businesses involve a high degree of risk. You should consider carefully the risks and uncertainties described below and the other information included in this Form 10-K, including Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data. While these are the risks and uncertainties we believe are most important for you to consider, you should know that they are not the only risks or uncertainties facing us or which may adversely affect our business. If any of the following risks or uncertainties actually occurs, our business, financial condition or results of operations could be adversely affected.

Demand for the majority of our services is substantially dependent on the levels of expenditures by the oil and gas industry. A substantial or an extended decline in oil and gas prices could result in lower expenditures by the oil and gas industry, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Demand for the majority of our services depends substantially on the level of expenditures by the oil and gas industry for the exploration, development and production of oil or natural gas reserves. These expenditures are generally dependent on the industry's view of future oil and natural gas prices and are sensitive to the industry's view of future economic growth and the resulting impact on demand for oil and natural gas. Declines in oil and natural gas prices could result in project modifications, delays or cancellations, general business disruptions, and delays in payment of, or nonpayment of, amounts that are owed to us, any of which could have a material adverse effect on our financial condition, results of operations and cash flows. The oil and gas industry has historically experienced periodic downturns, which have been characterized by diminished demand for oilfield services and downward pressure on the prices we charge. A significant downturn in the oil and gas industry could result in a reduction in demand for oilfield services and could adversely affect our financial condition, results of operations and cash flows. As a result of recent decreases in oil and gas prices, many of our customers have announced reduced capital spending budgets for 2015, and further reductions in oil and gas prices or prices remaining at current levels for a prolonged period may result in further capital budget reductions.

Oil and natural gas prices impact demand for our services. Decreases in prices for crude oil and natural gas or other factors may reduce demand for our services and substantially reduce our profitability or result in losses.

The success of our operations is significantly dependent upon the exploration and development activities of the major, independent and national oil and natural gas E&P companies and large integrated service companies that comprise our customer base. Oil and natural gas prices and market expectations regarding potential changes in these prices can be extremely volatile. Increases or decreases in oil and natural gas prices and expectations of future prices could have an impact on our customers' long-term exploration and development activities, which in turn could materially affect our business and financial performance. Higher oil and gas prices do not necessarily result immediately in increased drilling activity because our customers' expectations of future oil and gas prices typically drive demand for our drilling services.

Oil and gas prices declined significantly in the fourth quarter of 2014. Downward pressure on oil and gas prices has continued in 2015 and may continue for the foreseeable future. Any prolonged reduction in oil and gas prices will depress immediate levels of exploration, development and production activity, which could have a material adverse effect on our business, results of operations and financial condition.

Oil and gas prices and demand for our services also depends upon numerous factors which are beyond our control, including:

- the demand for oil and natural gas;
- the cost of exploring for, producing and delivering oil and natural gas;
- expectations regarding future energy prices;
- advances in exploration, development and production technology;
- the adoption or repeal of laws and government regulations, both in the United States and other countries;
- the imposition or lifting of economic sanctions against certain regions, persons and other entities;

- the number of ongoing and recently completed rig construction projects which may create overcapacity;
- local and worldwide military, political and economic events, including events in the oil producing regions of Africa, the Middle East, Russia, Central Asia, Southeast Asia and Latin America;
- the ability of the Organization of Petroleum Exporting Countries (OPEC) to set and maintain production levels and prices;
- the level of production by non-OPEC countries;
- weather conditions;
- expansion or contraction of worldwide economic activity, which affects levels of consumer and industrial demand;
- the rate of discovery of new oil and natural gas reserves;
- domestic and foreign tax policies;
- acts of terrorism in the United States or elsewhere;
- the development and use of alternative energy sources; and
- the policies of various governments regarding exploration and development of their oil and natural gas reserves.

A slowdown in economic activity may result in lower demand for our drilling and drilling related services and rental tools business, and could have a material adverse effect on our business.

A slowdown in economic activity in the United States or abroad could lead to uncertainty in corporate credit availability and capital market access and could reduce worldwide demand for energy and result in lower crude oil and natural gas prices. Our business depends to a significant extent on the level of international onshore drilling activity and GOM inland and offshore drilling activity for oil and natural gas. Depressed oil and natural gas prices from lower demand as a result of slow or negative economic growth would reduce the level of exploration, development and production activity, all of which could cause our revenues and margins to decline, decrease dayrates and utilization of our rigs and use of our rental tools and limit our future growth prospects. Any significant decrease in dayrates or utilization of our rigs or use of our rental tools could materially reduce our revenue and profitability. In addition, current and potential customers who depend on financing for their drilling projects may be forced to curtail or delay projects and may also experience an inability to pay suppliers and service providers, including us. Likewise, economic conditions in the United States or abroad could impact our vendors' and suppliers' ability to meet obligations to provide materials and services in general. All of these factors could have a material adverse effect on our business and financial results.

Rig upgrade, refurbishment and construction projects are subject to risks and uncertainties, including delays and cost overruns, which could have an adverse impact on our results of operations and cash flows.

We regularly make significant expenditures in connection with upgrading and refurbishing our rig fleet. These activities include planned upgrades to maintain quality standards, routine maintenance and repairs, changes made at the request of customers, and changes made to comply with environmental or other regulations. Rig upgrade, refurbishment and construction projects are subject to the risks of delay or cost overruns inherent in any large construction project, including the following:

- shortages of equipment or skilled labor;
- unforeseen engineering problems;
- unanticipated change orders;
- work stoppages;
- adverse weather conditions;
- unexpectedly long delivery times for manufactured rig components;
- unanticipated repairs to correct defects in construction not covered by warranty;
- failure or delay of third-party equipment vendors or service providers;
- unforeseen increases in the cost of equipment, labor or raw materials, particularly steel;
- disputes with customers, shipyards or suppliers;
- latent damages or deterioration to hull, equipment and machinery in excess of engineering estimates and assumptions;
- financial or other difficulties with current customers at shipyards and suppliers;
- loss of revenue associated with downtime to remedy malfunctioning equipment not covered by warranty;

- unanticipated cost increases;
- loss of revenue and payments of liquidated damages for downtime to perform repairs associated with defects, unanticipated equipment refurbishment and delays in commencement of operations; and
- lack of ability to obtain the required permits or approvals, including import/export documentation.

Any one of the above risks could adversely affect our financial condition and results of operations. Delays in the delivery of rigs being constructed or undergoing upgrade, refurbishment or repair may, in many cases, delay commencement of a drilling contract resulting in a loss of revenue to us, and may also cause our customer to renegotiate the drilling contract for the rig or terminate or shorten the term of the contract under applicable late delivery clauses, if any. If one of these contracts is terminated, we may not be able to secure a replacement contract on as favorable terms, if at all. Additionally, actual expenditures for required upgrades or to refurbish or construct rigs could exceed our planned capital expenditures, impairing our ability to service our debt obligations.

Failure to attract and retain skilled and experienced personnel could affect our operations.

We require skilled, trained and experienced personnel to provide our customers with the highest quality technical services and support for our drilling operations. We compete with other oilfield services businesses and other employers to attract and retain qualified personnel with the technical skills and experience we require. Competition for skilled labor and other labor required for our operations intensifies as the number of rigs activated or added to worldwide fleets or under construction increases, creating upward pressure on wages. In periods of high utilization, we have found it more difficult to find and retain qualified individuals. A shortage in the available labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult for us to attract and retain personnel and could require us to enhance our wage and benefits packages. Increases in our operating costs could adversely affect our business and financial results. Moreover, the shortages of qualified personnel or the inability to obtain and retain qualified personnel could negatively affect the quality, safety and timeliness of our operations.

Our debt levels and debt agreement restrictions may limit our liquidity and flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2014, we had:

- $615.0 million of long-term debt, including $10.0 million of current portion of long-term debt;
- $47.7 million of operating lease commitments; and
- $11.0 million of standby letters of credit.

Our ability to meet our debt service obligations depends on our ability to generate positive cash flows from operations. We have in the past, and may in the future, incur negative cash flows from one or more segments of our operating activities. Our future cash flows from operating activities will be influenced by the demand for our drilling services, the utilization of our rigs, the dayrates that we receive for our rigs, demand for our rental tools, oil and gas prices, general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control.

If we are unable to service our debt obligations, we may have to take one or more of the following actions:

- delay spending on capital projects, including maintenance projects and the acquisition or construction of additional rigs, rental tools and other assets;
- sell equity or assets; and
- restructure or refinance our debt.

Additional indebtedness or equity financing may not be available to us in the future for the refinancing or repayment of existing indebtedness, or if available, such additional indebtedness or equity financing may not be available on a timely basis, or on terms acceptable to us and within the limitations specified in our then existing debt instruments. In addition, in the event we decide to sell assets, we can provide no assurance as to the timing of any asset sales or the proceeds that could be realized from any such asset sale. Our ability to generate sufficient cash flow from operating activities to pay the principal of and interest on our indebtedness is subject to certain market conditions and other factors which are beyond our control.

Increases in the level of our debt and restrictions in the covenants contained in the instruments governing our debt could have important consequences to you. For example, they could:

- result in a reduction of our credit rating, which would make it more difficult for us to obtain additional financing on acceptable terms;

- require us to dedicate a substantial portion of our cash flows from operating activities to the repayment of our debt and the interest associated with our debt;
- limit our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt and creating liens on our properties;
- place us at a competitive disadvantage compared with our competitors that have relatively less debt; and
- make us more vulnerable to downturns in our business.

Our current operations and future growth may require significant additional capital, and the amount of our indebtedness could impair our ability to fund our capital requirements.

Our business requires substantial capital. We may require additional capital in the event of growth opportunities, unanticipated maintenance requirements or significant departures from our current business plan.

Additional financing may not be available on a timely basis or on terms acceptable to us and within the limitations contained in our Second Amended and Restated Credit Agreement (2015 Secured Credit Agreement) and the indentures governing our outstanding 7.50% Senior Notes due 2020 (7.50% Notes) and 6.75% Senior Notes due 2022 (6.75% Notes, and collectively with the 7.50% Notes, the Senior Notes). Failure to obtain additional financing, should the need for it develop, could impair our ability to fund capital expenditure requirements and meet debt service requirements and could have an adverse effect on our business.

Our 2015 Secured Credit Agreement and the indentures for our Senior Notes impose significant operating and financial restrictions, which may prevent us from capitalizing on business opportunities and taking some actions.

The 2015 Secured Credit Agreement and the indentures governing our senior notes impose significant operating and financial restrictions on us. These restrictions limit our ability to:

- make investments and other restricted payments, including dividends;
- incur additional indebtedness;
- create liens;
- engage in sale leaseback transactions;
- sell our assets or consolidate or merge with or into other companies; and
- engage in transactions with affiliates.

These limitations are subject to a number of important qualifications and exceptions. Our 2015 Secured Credit Agreement also requires us to maintain ratios for consolidated leverage, asset coverage, consolidated interest coverage, and consolidated senior secured leverage. These covenants may adversely affect our ability to finance our future operations and capital needs and to pursue available business opportunities. A breach of any of these covenants could result in a default with respect to the related indebtedness. If a default were to occur, the lenders under our 2015 Secured Credit Agreement and the holders of our Senior Notes could elect to declare the indebtedness, together with accrued interest, immediately due and payable. If the repayment of the indebtedness were to be accelerated after any applicable notice or grace periods, we may not have sufficient funds to repay the indebtedness.

Certain of our contracts are subject to cancellation by our customers without penalty and with little or no notice.

Certain of our contracts are subject to cancellation by our customers without penalty and with relatively little or no notice. In some cases our customers may terminate without cause. When drilling market conditions are depressed, a customer may no longer need a rig or rental tools that is currently under contract or may be able to obtain comparable equipment at lower dayrates. Further, due to government actions, a customer may no longer be able to operate in, or it may not be economical to operate in, certain regions. As a result, customers may leverage their termination rights in an effort to renegotiate contract terms.

Our customers may also seek to terminate contracts for cause, such as the loss of or a major damage to the drilling unit or other events that cause the suspension of drilling operations beyond a specified period of time. If we experience operational problems or if our equipment fails to function properly and cannot be repaired promptly, our customers will not be able to engage in drilling operations and may have the right to terminate the contracts. If equipment is not timely delivered to a customer or does not pass acceptance testing, a customer may in certain circumstances have the right to terminate the contract. The payment of a termination fee may not fully compensate us for the loss of the contract. Early termination of a contract may result in a rig or other equipment being idle for an extended period of time. The likelihood that a customer may seek to terminate a contract is increased during periods of market weakness. The cancellation or renegotiation of a number of our contracts could materially reduce our revenue and profitability.

We rely on a small number of customers and the loss of a significant customer could adversely affect us.

A substantial percentage of our revenues are generated from a relatively small number of customers and the loss of a significant customer could adversely affect us. In 2014, our largest customer, Exxon Neftegas Limited accounted for approximately 18.7 percent of our total revenues. Our drilling business depends on a limited number of key customers and the loss of any one or more key customers could have a material adverse effect on the business. Our consolidated results of operations could be adversely affected if any of our significant customers terminate their contracts with us, fail to renew our existing contracts or refuse to award new contracts to us.

The contract drilling and the rental tools businesses are highly competitive and cyclical, with intense price competition.

The contract drilling and rental tools markets are highly competitive and many of our competitors in both the contract drilling and rental tools businesses may possess greater financial resources than we do. Some of our competitors also are incorporated in countries that may provide them with significant tax advantages that are not available to us as a U.S. company and which may impair our ability to compete with them for many projects.

Contract drilling companies compete primarily on a regional basis, and competition may vary significantly from region to region at any particular time. Many drilling and workover rigs can be moved from one region to another in response to changes in levels of activity, provided market conditions warrant, which may result in an oversupply of rigs in an area. Many competitors have constructed numerous rigs during periods of high energy prices and, consequently, the number of rigs available in some of the markets in which we operate has exceeded the demand for rigs for extended periods of time, resulting in intense price competition. Most drilling contracts are awarded on the basis of competitive bids, which also results in price competition. Historically, the drilling service industry has been highly cyclical, with periods of high demand, limited equipment supply and high dayrates often followed by periods of low demand, excess equipment supply and low dayrates. Periods of low demand and excess equipment supply intensify the competition in the industry and often result in equipment being idle for long periods of time. During periods of decreased demand we typically experience significant reductions in dayrates and utilization. The Company, or its competition, may move rigs or other equipment from one geographic location to another location; the cost of which may be substantial. If we experience reductions in dayrates or if we cannot keep our equipment utilized, our financial performance will be adversely impacted. Prolonged periods of low utilization and dayrates could result in the recognition of impairment charges on certain of our rigs if future cash flow estimates, based upon information available to management at the time, indicate that the carrying value of these rigs may not be recoverable.

Our international operations are subject to governmental regulation and other risks.

We derive a significant portion of our revenues from our international operations. In 2014, we derived approximately 50.0 percent of our revenues from operations in countries other than the United States. Our international operations are subject to the following risks, among others:

- political, social and economic instability, war, terrorism and civil disturbances;
- economic sanctions imposed by the U.S. government against other countries, groups, or individuals, or economic sanctions imposed by other governments against the U.S. or businesses incorporated in the U.S.;
- limitations on insurance coverage, such as war risk coverage, in certain areas;
- expropriation, confiscatory taxation and nationalization of our assets;
- foreign laws and governmental regulation, including inconsistencies and unexpected changes in laws or regulatory requirements, and changes in interpretations or enforcement of existing laws or regulations;
- increases in governmental royalties;
- import-export quotas or trade barriers;
- hiring and retaining skilled and experienced workers, some of whom are represented by foreign labor unions;
- work stoppages;
- damage to our equipment or violence directed at our employees, including kidnapping;
- piracy of vessels transporting our people or equipment;
- unfavorable changes in foreign monetary and tax policies;
- solicitation by government officials for improper payments or other forms of corruption;
- foreign currency fluctuations and restrictions on currency repatriation;
- repudiation, nullification, modification or renegotiation of contracts; and

- other forms of governmental regulation and economic conditions that are beyond our control.

We currently have operations in 23 countries. Our operations are subject to interruption, suspension and possible expropriation due to terrorism, war, civil disturbances, political and capital instability and similar events, and we have previously suffered loss of revenue and damage to equipment due to political violence. Civil and political disturbances in international locations may affect our operations. We may not be able to obtain insurance policies covering risks associated with these types of events, especially political violence coverage, and such policies may only be available with premiums that are not commercially reasonable.

Our international operations are subject to the laws and regulations of a number of countries with political, regulatory and judicial systems and regimes that may differ significantly from those in the U.S. Our ability to compete in international contract drilling and rental tool markets may be adversely affected by foreign governmental regulations and/or policies that favor the awarding of contracts to contractors in which nationals of those foreign countries have substantial ownership interests or by regulations requiring foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. Furthermore, our foreign subsidiaries may face governmentally imposed restrictions or fees from time to time on the transfer of funds to us.

In addition, tax and other laws and regulations in some foreign countries are not always interpreted consistently among local, regional and national authorities, which can result in disputes between us and governing authorities. The ultimate outcome of these disputes is never certain, and it is possible that the outcomes could have an adverse effect on our financial performance.

A portion of the workers we employ in our international operations are members of labor unions or otherwise subject to collective bargaining. We may not be able to hire and retain a sufficient number of skilled and experienced workers for wages and other benefits that we believe are commercially reasonable.

We may experience currency exchange losses where revenues are received or expenses are paid in nonconvertible currencies or where we do not take protective measures against exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenues because of a shortage of convertible currency available to the country of operation, controls over currency exchange or controls over the repatriation of income or capital. Given the international scope of our operations, we are exposed to risks of currency fluctuation and restrictions on currency repatriation. We attempt to limit the risks of currency fluctuation and restrictions on currency repatriation where possible by obtaining contracts payable in U.S. dollars or freely convertible foreign currency. In addition, some parties with which we do business could require that all or a portion of our revenues be paid in local currencies. Foreign currency fluctuations, therefore, could have a material adverse effect upon our results of operations and financial condition.

The shipment of goods, services and technology across international borders subjects us to extensive trade laws and regulations. Our import activities are governed by the unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the U.S., control the export and re-export of certain goods, services and technology and impose related export recordkeeping and reporting obligations. Governments may also impose economic sanctions against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities. The laws and regulations concerning import activity, export recordkeeping and reporting, export control and economic sanctions are complex and constantly changing. These laws and regulations can cause delays in shipments and unscheduled operational downtime. Moreover, any failure to comply with applicable legal and regulatory trading obligations could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from governmental contracts, seizure of shipments and loss of import and export privileges.

Failure to comply with anti-corruption laws, such as the U.S. Foreign Corrupt Practices Act and the U.K. Bribery Act 2010, could result in fines, criminal penalties, negative commercial consequences and an adverse effect on our business.

The U.S. Foreign Corrupt Practices Act (FCPA), the U.K. Bribery Act 2010 and similar anti-corruption laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments or providing improper benefits for the purpose of obtaining or retaining business. Our policies mandate compliance with these anti-corruption laws. However, we operate in many parts of the world that experience corruption. If we are found to be liable for violations of these laws either due to our own acts or our omissions or due to the acts or omissions of others (including our joint ventures partners, our agents or other third party representatives), we could suffer from commercial, civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial condition and results of operations.

We are not fully insured against all risks associated with our business.

We ordinarily maintain insurance against certain losses and liabilities arising from our operations. However, we do not insure against all operational risks in the course of our business. Due to the high cost, high self-insured retention and limited coverage insurance for windstorms in the GOM we have elected not to purchase windstorm insurance for our inland barges in the GOM. Although we have retained the risk for physical loss or damage for these rigs arising from a named windstorm we have procured insurance coverage for removal of a wreck caused by a windstorm. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial position and results of operations.

We are subject to hazards customary for drilling operations, which could adversely affect our financial performance if we are not adequately indemnified or insured.

Substantially all of our operations are subject to hazards that are customary for oil and natural gas drilling operations, including blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, oil and natural gas well fires and explosions, natural disasters, pollution, mechanical failure and damage or loss during transportation. Some of our fleet is also subject to hazards inherent in marine operations, either while on-site or during mobilization, such as capsizing, sinking, grounding, collision, damage from severe weather and marine life infestations. These hazards could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. We have had accidents in the past due to some of these hazards. We may not be able to insure against these risks or to obtain indemnification to adequately protect us against liability from all of the consequences of the hazards and risks described above. The occurrence of an event not fully insured against or for which we are not indemnified, or the failure of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses. In addition, insurance may not continue to be available to cover any or all of these risks. For example, pollution, reservoir damage and environmental risks generally are not fully insurable. Even if such insurance is available, insurance premiums or other costs may rise significantly in the future, making the cost of such insurance prohibitive. For a description of our indemnification obligations and insurance, see Item 1. Business — Insurance and Indemnification.

Certain areas in and near the GOM are subject to hurricanes and other extreme weather conditions. When operating in and near the GOM, our drilling rigs and rental tools may be located in areas that could cause them to be susceptible to damage or total loss by these storms. In addition, damage caused by high winds and turbulent seas to our rigs, our shore bases and our corporate infrastructure could potentially cause us to curtail operations for significant periods of time until the effects of the damages can be repaired. In addition, our rigs in arctic regions can be affected by seasonal weather so severe, conditions are deemed too unsafe for operations.

Government regulations may reduce our business opportunities and increase our operating costs.

Government regulations control and often limit access to potential markets and impose extensive requirements concerning employee privacy and safety, environmental protection, pollution control and remediation of environmental contamination. Environmental regulations, including species protections, prohibit access to some locations and make others less economical, increase equipment and personnel costs, and often impose liability without regard to negligence or fault. In addition, governmental regulations, such as those related to climate change, may discourage our customers' activities, reducing demand for our products and services. We may be liable for damages resulting from pollution of offshore waters and, under United States regulations, must establish financial responsibility in order to drill offshore. See Item 1. Business — Environmental Considerations.

Regulation of greenhouse gases and climate change could have a negative impact on our business.

Some scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" (GHGs) and including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of GHG emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide. Legislative and regulatory measures to address concerns that emissions of GHGs are contributing to climate change are in various phases of discussions or implementation at the international, national, regional and state levels.

Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws, regulations, treaties or international agreements related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business. In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our rigs, impact our ability to conduct our operations and/or result in a disruption of our customers' operations.

We are regularly involved in litigation, some of which may be material.

We are regularly involved in litigation, claims and disputes incidental to our business, which at times may involve claims for significant monetary amounts, some of which would not be covered by insurance. We undertake all reasonable steps to defend ourselves in such lawsuits. Nevertheless, we cannot predict the ultimate outcome of such lawsuits and any resolution which is adverse to us could have a material adverse effect on our financial condition. See Note 13 - Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data for a discussion of the material legal proceedings affecting us.

A catastrophic event could occur, materially impacting our liquidity, results of operations, and financial condition.

Our services are performed in harsh environments, and the work we perform can be dangerous. Catastrophic events such as a well blowout, fire, or explosion can occur, resulting in property damage, personal injury, death, pollution, and environmental damage. Typically, we are indemnified by our customers for injuries and property damage resulting from these types of events (except for injury to our employees and subcontractors and property damage to ours and our subcontractors' equipment). However, we could be exposed to significant loss if adequate indemnity provisions or insurance are not in place, if indemnity provisions are unenforceable or otherwise invalid, or if our customers are unable or unwilling to satisfy any indemnity obligations.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact the demand for rental tools.

Hydraulic fracturing is a process sometimes used in the completion of oil and natural gas wells whereby water, other liquids, sand and chemicals are injected under pressure into subsurface formations to stimulate natural gas and, to a lesser extent, oil production. Various governmental entities (within and outside the United States) are in the process of studying, restricting, regulating, or preparing to regulate hydraulic fracturing, directly and indirectly. For example, many state governments now require the disclosure of chemicals used in the fracturing process. The U.S. EPA has taken the position that hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids are subject to permitting requirements under the Safe Drinking Water Act; has adopted air emissions standards that apply to well completion activities; is developing new standards for wastewater discharges associated with hydraulic fracturing; and is conducting a study on the impacts of hydraulic fracturing on groundwater. The Bureau of Land Management has also proposed regulations for hydraulic fracturing activities that would be unique to federal lands. In addition, some jurisdictions have imposed an express or de facto ban on hydraulic fracturing. These and other developments could cause operational delays or increased costs in exploration and production, which could adversely affect the demand for our rental tools.

A cybersecurity incident could negatively impact our business and our relationships with customers.

If our systems for protecting against cybersecurity 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, having our business operations interrupted, and increased costs to prevent, respond to, or mitigate cybersecurity attacks. These risks could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition.

Our acquisitions, dispositions, and investments may not result in the realization of savings, the creation of efficiencies, the generation of cash or income, or the reduction of risk, which may have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We continually seek opportunities to maximize efficiency and value through various transactions, including purchases or sales of assets, businesses, investments, or joint ventures. These transactions are intended to result in the realization of savings, the creation of efficiencies, the offering of new products or services, the generation of cash or income, or the reduction of risk. Acquisition transactions may be financed by additional borrowings or by the issuance of our common stock. These transactions may also affect our consolidated results of operations.

These transactions also involve risks, and we cannot ensure that:

- any acquisitions would result in an increase in income or earnings per share;
- any acquisitions would be successfully integrated into our operations and internal controls;
- the due diligence prior to an acquisition would uncover situations that could result in financial or legal exposure, or that we will appropriately quantify the exposure from known risks;
- any disposition would not result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions would not adversely affect our cash available for capital expenditures and other uses;
- any dispositions, investments, acquisitions, or integrations would not divert management resources; or
- any dispositions, investments, acquisitions, or integrations would not have a material adverse effect on our results of operations or financial condition.

The market price of our common stock has fluctuated significantly.

The market price of our common stock may continue to fluctuate in response to various factors and events, most of which are beyond our control, including the following:

- the other risk factors described in this Form 10-K, including changes in oil and natural gas prices;
- a shortfall in rig utilization, operating revenue or net income from that expected by securities analysts and investors;
- changes in securities analysts' estimates of the financial performance of us or our competitors or the financial performance of companies in the oilfield service industry generally;
- changes in actual or market expectations with respect to the amounts of exploration and development spending by oil and natural gas companies;
- general conditions in the economy and in energy-related industries;
- general conditions in the securities markets;
- political instability, terrorism or war; and
- the outcome of pending and future legal proceedings, investigations, tax assessments and other claims.

DISCLOSURE NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K contains statements that are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended, (the Exchange Act). All statements contained in this Form 10-K, other than statements of historical facts, are forward-looking statements for purposes of these provisions, including any statements regarding:

- stability or volatility of prices and demand for oil and natural gas;
- levels of oil and natural gas exploration and production activities;
- demand for contract drilling and drilling-related services and demand for rental tools and related services;
- our future operating results and profitability;
- our future rig utilization, dayrates and rental tools activity;
- entering into new, or extending existing, drilling or rental contracts and our expectations concerning when operations will commence under such contracts;
- entry into new markets or potential exit from existing markets;
- growth through acquisitions of companies or assets;
- organic growth of our operations;
- construction or upgrades of rigs and expectations regarding when these rigs will commence operations;
- capital expenditures for acquisition of rental tools, rigs, construction of new rigs or major upgrades to existing rigs;
- entering into joint venture agreements;
- our future liquidity;
- the sale or potential sale of assets or references to assets held for sale;
- availability and sources of funds to refinance our debt and expectations of when debt will be reduced;
- the outcome of pending or future legal proceedings, investigations, tax assessments and other claims;
- the availability of insurance coverage for pending or future claims;
- the enforceability of contractual indemnification in relation to pending or future claims; and
- compliance with covenants under our debt agreements.

In some cases, you can identify these statements by forward-looking words such as "anticipate," "believe," "could," "estimate," "expect," "intend," "outlook," "may," "should," "will" and "would" or similar words. Forward-looking statements are based on certain assumptions and analyses we make in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are relevant. Although we believe that our assumptions are reasonable based on information currently available, those assumptions are subject to significant risks and uncertainties, many of which are outside of our control. The following factors, as well as any other cautionary language included in this Form 10-K, provide examples of risks, uncertainties and events that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements:

- fluctuations in the market prices of oil and natural gas, including the inability or unwillingness of our customers to fund drilling programs in low price cycles;
- worldwide economic and business conditions that adversely affect market conditions and/or the cost of doing business, including potential currency devaluations or collapses;
- our inability to access the credit markets;
- U.S. credit market volatility resulting from the U.S. national debt and potential further downgrades of the U.S. credit rating;
- the U.S. economy and the demand for oil and natural gas;
- low U.S. oil and natural gas prices that could adversely affect our U.S. drilling, barge rig and U.S. rental tools businesses;
- worldwide demand for oil;
- imposition of trade restrictions, including additional economic sanctions and export/re export controls affecting our business operations in Russia;
- unanticipated operating hazards and uninsured risks;
- political instability, terrorism or war;
- governmental regulations, including changes in accounting rules or tax laws that adversely affect the cost of doing business or our ability to remit funds to the U.S.;

- changes in the tax laws that would allow double taxation on foreign sourced income;
- the outcome of investigations into possible violations of laws;
- adverse environmental events;
- adverse weather conditions;
- global health concerns;
- changes in the concentration of customer and supplier relationships;
- ability of our customers and suppliers to obtain financing for their operations;
- ability of our customers to fund drilling plans;
- unexpected cost increases for new construction and upgrade and refurbishment projects;
- delays in obtaining components for capital projects and in ongoing operational maintenance and equipment certifications;
- shortages of skilled labor;
- unanticipated cancellation of contracts by customers or operators;
- breakdown of equipment;
- other operational problems including delays in start-up or commissioning of rigs;
- changes in competition;
- any failure to realize expected benefits from acquisitions;
- the effect of litigation and contingencies; and
- other similar factors, some of which are discussed in documents referred to or incorporated by reference into this Form 10-K and our other reports and filings with the SEC.

Each forward-looking statement speaks only as of the date of this Form 10-K, 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. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Form 10-K could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We lease corporate headquarters office space in Houston, Texas and own our U.S. rental tools headquarters office in New Iberia, Louisiana. We lease regional headquarters space in Aberdeen, Scotland and Dubai, UAE related to our international rental tools business. Additionally, we own and/or lease office space and operating facilities in various other locations, domestically and internationally, including facilities where we hold inventories of rental tools and locations in close proximity to where we provide services to our customers. Additionally, we own and/or lease facilities necessary for administrative and operational support functions.

Land and Barge Rigs

The table below shows the locations and drilling depth ratings of our rigs as of December 31, 2014. The table excludes three rigs currently not available for service, which are Rig 140, located in Papua New Guinea, and Rig 225 and Rig 252, located in Indonesia.

Name	Type(1)	Year entered into service/ upgraded	Drilling depth rating (in feet)	Location
International				
Europe, Middle East, and Asia				
Rig 231	L	1981/1997	13,000	Indonesia
Rig 253	L	1982/1996	15,000	Indonesia
Rig 226	HH	1989/2010	18,000	Papua New Guinea
Rig 107	L	1983/2009	15,000	Kazakhstan
Rig 216	L	2001/2009	25,000	Kazakhstan
Rig 249	L	2000/2009	25,000	Kazakhstan
Rig 257	B	1999/2010	30,000	Kazakhstan
Rig 258	L	2001/2009	25,000	Kazakhstan
Rig 247	L	1981/2008	18,000	Iraq, Kurdistan Region
Rig 269	L	2008	21,000	Iraq, Kurdistan Region
Rig 265 (2)	L	2007	20,000	Iraq, Kurdistan Region
Rig 264	L	2007	20,000	Tunisia
Rig 270	L	2011	21,000	Russia
Latin America				
Rig 121	L	1980/2007	18,000	Colombia
Rig 268	L	1978/2009	30,000	Colombia
Rig 271	L	1982/2009	30,000	Colombia
Rig 122	L	1980/2008	18,000	Mexico
Rig 165	L	1978/2007	30,000	Mexico
Rig 221	L	1982/2007	30,000	Mexico
Rig 256	L	1978/2007	25,000	Mexico
Rig 266	L	2008	20,000	Mexico
Rig 267	L	2008	20,000	Mexico
U.S. Land and Barge Drilling				
Rig 8	B	1978/2007	14,000	GOM
Rig 12	B	1979/2006	18,000	GOM
Rig 15	B	1978/2007	15,000	GOM
Rig 20	B	1981/2007	13,000	GOM
Rig 21	B	1979/2012	14,000	GOM
Rig 30	B	2014	20,000	GOM
Rig 50	B	1981/2006	20,000	GOM
Rig 51	B	1981/2008	20,000	GOM
Rig 54	B	1980/2006	25,000	GOM
Rig 55	B	1981/2014	25,000	GOM
Rig 72	B	1982/2005	25,000	GOM
Rig 76	B	1977/2009	30,000	GOM
Rig 77	B	2006/2006	30,000	GOM
Rig 272	L	2013	18,000	Alaska
Rig 273	L	2012	18,000	Alaska

1) Type is defined as: L — land rig; B — barge rig; HH — heli-hoist land rig.

2) Rig 265 was in transit from Tunisia to Iraq at December 31, 2014.

The following table presents our average utilization rates and rigs available for service for the years ended December 31, 2014 and 2013:

	December 31,	
	2014	2013
U.S. Land & Barge Rigs		
U.S. Barge Drilling Rigs		
Rigs available for service (1)	12.1	11.0
Utilization rate of rigs available for service (2)	72%	91%
U.S. Drilling Rigs		
Rigs available for service (1)	2.0	1.9
Utilization rate of rigs available for service (2)	100%	100%
International Land & Barge Rigs		
Europe, Middle East, and Asia Region		
Rigs available for service (1)	13.0	14.0
Utilization rate of rigs available for service (2)	77%	49%
Latin America Region		
Rigs available for service (1)	9.0	9.5
Utilization rate of rigs available for service (2)	60%	75%
Total International Land & Barge Rigs		
Rigs available for service (1)	22.0	23.5
Utilization rate of rigs available for service (2)	70%	60%

1) The number of rigs available for service is determined by calculating the number of days each rig was in our fleet and was under contract or available for contract. For example, a rig under contract or available for contract for six months of a year is 0.5 rigs available for service during such year. Our method of computation of rigs available for service may not be comparable to other similarly titled measures of other companies.

2) Rig utilization rates are based on a weighted average basis assuming 365 days availability for all rigs available for service. Rigs acquired or disposed of are treated as added to or removed from the rig fleet as of the date of acquisition or disposal. Rigs that are in operation or fully or partially staffed and on a revenue-producing standby status are considered to be utilized. Rigs under contract that generate revenues during moves between locations or during mobilization or demobilization are also considered to be utilized. Our method of computation of rig utilization may not be comparable to other similarly titled measures of other companies.

Item 3. Legal Proceedings

For information on Legal Proceedings, see Note 13 - Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data, which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Parker Drilling Company’s common stock is listed for trading on the New York Stock Exchange under the symbol “PKD.” The following table sets forth the high and low sales prices per share of our common stock, as reported on the New York Stock Exchange composite tape, for the periods indicated:

	2014		2013	
Quarter	High	Low	High	Low
First	$ 8.67	$ 6.85	$ 6.18	$ 4.27
Second	$ 7.39	$ 5.88	$ 5.20	$ 3.75
Third	$ 7.03	$ 4.89	$ 6.42	$ 4.92
Fourth	$ 5.17	$ 2.58	$ 8.50	$ 5.68

Most of our stockholders maintain their shares as beneficial owners in “street name” accounts and are not, individually, stockholders of record. As of February 23, 2015, there were 1,585 holders of record of our shares and we had an estimated 20,775 beneficial owners.

Our 2015 Secured Credit Agreement and the indentures for the Senior Notes restrict the payment of dividends. In the past we have not paid dividends on our common stock and we have no present intention to pay dividends on our common stock in the foreseeable future.

Issuer Purchases of Equity Securities

The Company currently has no active share repurchase programs.

Item 6. Selected Financial Data

The following table presents selected historical consolidated financial data derived from the audited financial statements of Parker Drilling Company for each of the five years in the period ended December 31, 2014. The following financial data should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data.

	Year Ended December 31,				
	2014	2013 (1)	2012	2011 (2)	2010
Dollars in Thousands, Except Per Share Amounts					
Income Statement Data					
Total revenues	$ 968,684	$ 874,172	$ 677,761	$ 686,234	$ 659,475
Total operating income (loss)	120,220	101,872	107,273	(41,837)	45,107
Net income (loss)	24,461	27,179	37,098	(50,645)	(14,708)
Net income (loss) attributable to controlling interest	23,451	27,015	37,313	(50,451)	(14,461)
Basic earnings per share:					
Net income (loss)	$ 0.19	$ 0.23	$ 0.32	$ (0.43)	$ (0.13)
Net income (loss) attributable to controlling interest	$ 0.19	$ 0.23	$ 0.32	$ (0.43)	$ (0.13)
Diluted earnings per share:					
Net income (loss)	$ 0.19	$ 0.22	$ 0.31	$ (0.43)	$ (0.13)
Net income (loss) attributable to controlling interest	$ 0.19	$ 0.22	$ 0.31	$ (0.43)	$ (0.13)
Balance Sheet Data					
Total assets	$ 1,520,659	$ 1,534,756	$ 1,255,733	$ 1,216,246	$ 1,274,555
Total long-term debt including current portion of long-term debt	615,000	653,781	479,205	482,723	472,862
Total equity	666,214	633,142	590,633	544,050	588,066

1) The 2013 results include $22.5 million of acquisition costs related to the acquisition of ITS on April 22, 2013. See Note 2 — Acquisition of ITS in Item 8. Financial Statements and Supplementary Data for further discussion.

2) The 2011 results reflect a $170.0 million ($109.1 million, net of taxes of $60.9 million) non-cash pretax impairment charge related to our two arctic-class drilling rigs located in Alaska. See Note 4 — Property, Plant and Equipment in Item 8. Financial Statements and Supplementary Data.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's discussion and analysis (MD&A) should be read in conjunction with Item 8. Financial Statements and Supplementary Data.

Executive Overview

We achieved important operational gains during 2014 in all of our key business areas. The progress we made in 2014 strengthened our ability to provide innovative, reliable and efficient solutions to customers and operate successfully in the current challenging business environment.

Our drilling operations achieved increases in revenues and gross margin in 2014, compared with 2013, with contributions from most of our drilling business segments.

- Our international drilling operations increased average utilization to 70 percent for the year, up from 60 percent for the prior year. At the end of the year, 18 of our 22 international drilling rigs were under contract. Market disruptions in Iraq, regulatory changes in the Latin America region and the year-end decline in oil prices hampered our ability to achieve further utilization gains.
- The number of customer-owned rigs under O&M contracts increased as the Berkut platform moved into operation alongside our other O&M activities on Sakhalin Island, Russia and we secured a contract in Abu Dhabi to operate two island-based land rigs drilling extended reach wells.
- Our U.S. drilling business achieved strong financial gains due to solid operational performance by our two arctic-class drilling rigs in Alaska.
- Our GOM barge drilling operations achieved average utilization of 72 percent in 2014, compared with 91 percent for 2013, and increased its average dayrate by 16 percent compared with 2013. This was the result of a strong first three quarters moderated by the impacts of oil price declines on fourth quarter activity. In addition, we completed the reconstruction of Rig 55B and acquired Rig 30B, broadening the operational capabilities of our diversified barge rig fleet.

Our rental tools segment results reflected a full year's contribution from the April 2013 acquisition of ITS, a significant addition to the Company's position in the international rental tools market.

- The average utilization index for our U.S. rental tools tubular goods rose to 91 in 2014, compared with 80 in 2013.
- We increased our participation in the U.S. GOM offshore drilling market with investments in equipment to service the growth in deepwater drilling activity.
- Our international rental tools business produced improved results in the second half of the year from strong gains in the Middle East, Europe and Latin America, after being slowed earlier in 2014 by disruptive events in Iraq and delayed development in Mexico.

We further strengthened our financial position by reducing our total debt by $39 million during the year and refinancing $360 million of debt at lower interest rates with extended maturities. In January 2015 we enhanced our liquidity and financial flexibility by increasing our revolving credit facility from $80 million to $200 million, extending its maturity to 2020, and repaying our $30 million Term Loan with a $30 million draw on the increased revolving credit facility.

Executive Outlook

We expect 2015 to be a challenging year. The steep and rapid decline in oil prices has led to a sharp reduction in drilling activities in U.S. land and GOM inland and shallow water markets. This also is putting increased pressure on prices for our services. We anticipate the downturn in our U.S. markets will be severe and expect our international markets to be impacted as well, though with less severity.

As a result, we expect continued softness in rental tool demand and pricing in U.S. land drilling markets, continued low utilization in the U.S. barge drilling market with further declines in dayrates and some weakness in utilization and dayrates to develop in our international drilling markets. We expect the impact on our U.S. rental tools business to be moderated by our growing participation in the U.S. GOM deepwater drilling market. In addition, we anticipate stronger results from our international rental tools business due to our significant presence in the Middle East and recent gains in operating performance. We do not anticipate any significant changes in our international O&M projects or in our Alaska operations.

We do not know how deep this downcycle may go or how long it may last. We are taking actions across the company to lower our cost base, sustain our utilization, manage our cash and liquidity, and preserve our ability to respond as opportunities develop.

Results of Operations

We analyze financial results for each of our five reportable segments. The reportable segments presented are consistent with our reportable segments discussed in Note 12 — Reportable Segments in Item 8. Financial Statements and Supplementary Data. We historically reported a sixth reportable segment, Construction Contract, for which there was no activity for the year ended December 31, 2014 or December 31, 2013. As a result of our reversal of reserves relating to this segment in the fourth quarter of 2013, this segment has been included in the below results of operations.

We monitor our business segments based on several criteria, including operating gross margin and operating gross margin excluding depreciation and amortization. Operating gross margin excluding depreciation and amortization is computed as revenues less direct operating expenses, and excludes depreciation and amortization expense, where applicable; operating gross margin percentages are computed as operating gross margin as a percent of revenues. The operating gross margin amounts and operating gross margin percentages should not be used as a substitute for those amounts reported under U.S. GAAP. Management believes this information is useful to our investors as it more accurately reflects the cash flow from operations generated by each segment.

Year ended December 31, 2014 Compared with Year ended December 31, 2013

Revenues of $968.7 million for the year ended December 31, 2014 increased $94.5 million, or 10.8 percent, from the comparable 2013 period. Operating gross margin decreased 8.5 percent to $154.2 million for the year ended December 31, 2014 as compared to $168.4 million for the year ended December 31, 2013.

The following is an analysis of our operating results for the comparable periods by reportable segment:

	Year Ended December 31,			
	2014		2013	
Dollars in Thousands				
Revenues:				
Rental Tools	$ 347,766	36%	$ 310,041	35%
U.S. Barge Drilling	137,113	14%	136,855	16%
U.S. Drilling	79,984	8%	66,928	8%
International Drilling	360,588	37%	333,962	38%
Technical Services	43,233	5%	26,386	3%
Construction Contract	—	—%	—	—%
Total revenues	968,684	100%	874,172	100%
Operating gross margin excluding depreciation and amortization:				
Rental Tools	137,123	39%	147,017	47%
U.S Barge Drilling	63,759	47%	65,595	48%
U.S. Drilling	22,268	28%	11,901	18%
International Drilling	72,617	20%	71,078	21%
Technical Services	3,536	8%	2,181	8%
Construction Contract	—	—%	4,728	n/a
Total operating gross margin excluding depreciation and amortization	299,303	31%	302,500	35%
Depreciation and amortization	(145,121)		(134,053)	
Total operating gross margin	154,182		168,447	
General and administrative expense	(35,016)		(68,025)	
Provision for reduction in carrying value of certain assets	—		(2,544)	
Gain on disposition of assets, net	1,054		3,994	
Total operating income	$ 120,220		$ 101,872	

Operating gross margin amounts are reconciled to our most comparable U.S. GAAP measure as follows:

Dollars in Thousands	Rental Tools	U.S. Barge Drilling	U.S. Drilling	International Drilling	Technical Services	Construction Contract[2]
Year ended December 31, 2014						
Operating gross margin[1]	$ 72,946	$ 42,641	$ 6,320	$ 28,966	$ 3,309	$ —
Depreciation and amortization	64,177	21,118	15,948	43,651	227	—
Segment operating gross margin excluding depreciation and amortization	$ 137,123	$ 63,759	$ 22,268	$ 72,617	$ 3,536	$ —
Year ended December 31, 2013						
Operating gross margin[1]	$ 91,164	$ 51,257	$ (4,484)	$ 23,732	$ 2,050	$ 4,728
Depreciation and amortization	55,853	14,338	16,385	47,346	131	—
Segment operating gross margin excluding depreciation and amortization	$ 147,017	$ 65,595	$ 11,901	$ 71,078	$ 2,181	$ 4,728

(1) Operating gross margin is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

(2) The Construction Contract segment does not incur depreciation and amortization.

Rental Tools

Our rental tools segment includes both U.S. and international operations. Historically we have discussed the results of this segment by reference to our U.S. rental tools business, which principally was represented by our Quail Tools brand, and our international rental tools business, which principally was represented by ITS. As we have integrated the ITS business into our rental tools segment, both our Quail Tools and ITS brands are represented in the U.S. and international operations. Accordingly, in the current and future reporting periods we will discuss this segment on the basis of the U.S. market and the international market.

Rental tools segment revenues increased $37.7 million, or 12.2 percent, to $347.8 million for the year ended December 31, 2014 compared to $310.0 million for the year ended December 31, 2013. The increase was due to a $26.7 million increase in our international revenues and an $11.0 million increase in our U.S. revenues. The increase in international revenues was primarily due to a full year of revenues from ITS, which contributed an increase of $23.4 million of revenues for the year ended December 31, 2014. The increase in U.S. rental tools revenues was due to increased activity in the offshore GOM market and increased activity in the U.S. land drilling market.

Rental tools segment operating gross margin excluding depreciation and amortization decreased $9.9 million, or 6.7 percent, to $137.1 million for the year ended December 31, 2014 compared with $147.0 million for the year ended December 31, 2013. The decrease was primarily due to a reduction in gross margin excluding depreciation and amortization for our international operations, resulting from lower utilization, increased costs related to relocation of facilities and an increase in the allowance for doubtful accounts. This decline was slightly offset by an increase in gross margin excluding depreciation and amortization for our U.S. operations due to the increase in activity in the offshore GOM and U.S. land drilling markets, despite an increase in competitive conditions that have led to lower product pricing for rental tools and related activities.

U.S. Barge Drilling

U.S. barge drilling segment revenues increased $0.3 million, or 0.2 percent, to $137.1 million for the year ended December 31, 2014, as compared with revenues of $136.9 million for the year ended December 31, 2013. The increase in revenues was primarily due to higher average dayrates for the U.S. barge rig fleet, including benefits from the addition to our operating fleet of rigs 55B and 30B in the second and third quarters, respectively, of 2014. The increase was partially offset by lower utilization primarily due to a decline in market opportunities as a result of lower oil prices late in 2014.

U.S. barge drilling segment operating gross margin excluding depreciation and amortization decreased $1.8 million, or 2.8 percent, to $63.8 million for the year ended December 31, 2014, compared with $65.6 million for the year ended December 31, 2013. This decrease is primarily due to lower utilization caused by lower oil prices late in 2014.

U.S. Drilling

U.S. drilling segment revenues increased $13.1 million, or 19.5 percent, to $80.0 million for the year ended December 31, 2014, compared with $66.9 million for the year ended December 31, 2013. This increase in revenues is the result of a full year of operations in 2014 for our two arctic-class drilling rigs in Alaska, compared with 2013, in which one rig was not operational until February 2013. Additionally, the O&M contract supporting three platform operations located offshore California generated higher reimbursable revenues and was operating for the full year ended December 31, 2014, compared with 2013, in which this contract commenced in February 2013.

U.S. drilling segment operating gross margin excluding depreciation and amortization increased $10.4 million, or 87.1 percent, to $22.3 million for the year ended December 31, 2014 compared with $11.9 million for the year ended December 31, 2013. The increase in operating gross margin excluding depreciation and amortization for this segment is mainly due to both arctic-class rigs being fully operational and lower operating expenses. Additionally, we collected a previously reserved receivable allowing us to reverse the reserve during the first quarter of 2014.

International Drilling

International drilling segment revenues increased $26.6 million, or 8.0 percent, to $360.6 million for the year ended December 31, 2014, compared with $334.0 million for the year ended December 31, 2013. The increase in revenues is primarily due to higher drilling revenues through the operation of rigs we own, resulting from an increase in utilization, coupled with higher revenues generated by our O&M contracts.

Revenues related to Parker-owned rigs increased $17.9 million, or 8.8 percent, to $220.8 million for the year ended December 31, 2014 compared with $202.9 million for the year ended December 31, 2013. The increase in revenues was primarily due to an increase in utilization in our Sakhalin Island operations and an increase in our utilization in the Kurdistan Region of Iraq where we successfully deployed two previously idle rigs. These increases were partially offset by reduced revenues due to a decline in rig fleet utilization in our Latin America region.

O&M revenues increased $8.8 million, or 6.7 percent, to $139.8 million, for the year ended December 31, 2014 compared to $131.1 million for the year ended December 31, 2013. The increase in revenues from our O&M contracts was primarily due to increased activity and higher dayrates associated with our Sakhalin Island O&M operations, which included the startup of the Berkut platform project which began drilling operations in the fourth quarter. This increase was partially offset by the completion of an O&M project in Papua New Guinea in May 2014. Approximately $51.2 million and $46.4 million of O&M revenues were attributable to reimbursable costs for the years ended December 31, 2014 and 2013, respectively. Reimbursable revenues add to revenues but have a minimal impact on operating margins.

International drilling operating gross margin excluding depreciation and amortization increased $1.5 million, or 2.2 percent, to $72.6 million for the year ended December 31, 2014, compared with $71.1 million for the year ended December 31, 2013. The increase in operating gross margin excluding depreciation and amortization for the year ended December 31, 2014 was from our O&M operations slightly offset by a decrease in margins for our Parker-owned rig operations.

Operating gross margin excluding depreciation and amortization related to Parker-owned rigs was $46.4 million and $51.0 million for the years ended December 31, 2014 and 2013, respectively. The decrease in operating gross margin excluding depreciation and amortization was primarily due to the impact of net mobilization costs associated with the redeployment of two Parker-owned rigs from Kazakhstan to the Kurdistan Region of Iraq and their high initial operating costs as well as an increase in operating costs in our Papua New Guinea operations and decline in rig fleet utilization in our Latin America region.

Operating gross margin excluding depreciation and amortization generated by our O&M operations was $26.2 million and $20.0 million for the years ended December 31, 2014 and 2013, respectively. The increase in operating gross margin excluding depreciation and amortization is primarily due to increased activity and higher revenues and lower operating costs associated with our Sakhalin Island O&M operations, which included the startup of the Berkut platform project which began drilling operations in the fourth quarter. This increase was partially offset by the completion of an O&M project in Papua New Guinea in May 2014 discussed above.

Technical Services

Technical services segment revenues increased $16.8 million, or 63.8 percent, to $43.2 million for the year ended December 31, 2014, compared with $26.4 million for the year ended December 31, 2013. The increase is primarily due to a new FEED contract entered into during the fourth quarter of 2013 and increased activity under the vendor services phase of the Berkut platform project.

Operating gross margin excluding depreciation and amortization for this segment increased by $1.4 million to $3.5 million for the year ended December 31, 2014, compared with gross margin excluding depreciation and amortization for the year ended December 31, 2013. The increase is primarily the result of the revenue mix for the FEED project described above.

Construction Contract

This segment was created for and only includes the Liberty extended-reach drilling rig construction project which our customer canceled in 2011 prior to final completion. Our construction contract segment revenues were zero for the years ended December 31, 2014 and 2013. This segment reported zero and $4.7 million of operating gross margin excluding depreciation and amortization for the years ended December 31, 2014 and 2013, respectively. The operating gross margin excluding depreciation and amortization generated during the year ended December 31, 2013 resulted from the close-out of the Liberty project.

The Liberty rig construction contract was a fixed-fee and reimbursable contract that we accounted for on a percentage of completion basis. We recognized $335.5 million in revenues and $11.7 million of operating gross margin over the life of the contract. Over the course of the project, we established a project contingency reserve, which we maintained for potential claims by our subcontractors, vendors and customer. Due to the closure of all material claims, for which payments have been made or otherwise resolved or which are barred by the applicable statute of limitations, during the fourth quarter of 2013, we reversed the contingency reserve resulting in the operating gross margin excluding depreciation and amortization recognized for the year ended December 31, 2013.

Other Financial Data

General and administrative expense

General and administrative expense decreased $33.0 million to $35.0 million for the year ended December 31, 2014, compared with $68.0 million for the year ended December 31, 2013. The general and administrative expense decrease was due primarily to approximately $22.5 million of costs incurred during 2013 related to the ITS Acquisition that did not recur in 2014. During 2013 we also incurred severance costs related to the departure of our former chief financial officer and our executive chairman, and incurred higher legal costs for matters related to our deferred prosecution agreement and settlements with the DOJ and SEC, neither of which recurred during 2014. General and administrative expense during 2014 also benefited from a $2.75 million reimbursement from escrow related to the ITS Acquisition to reimburse the Company for certain post-acquisition expenditures. See Note 13 - Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data for further discussion.

Provision for reduction in carrying value of certain assets

During 2014, the provision for reduction in carrying value of certain assets was zero. During 2013, the provision for reduction in carrying value of certain assets was $2.5 million which was comprised of non-cash charges recognized for three rigs reclassified from assets held for sale to assets held and used for which carrying values exceeded fair values. Management concluded, based on the facts and circumstances at the time, it was no longer probable that the sales of the rigs sale would be consummated.

Gain on disposition of assets

Net gains recorded on asset dispositions for the years ended December 31, 2014 and 2013 were $1.1 million and $4.0 million, respectively. The net gains for 2014 were primarily the result of long-lived asset sales, including the sale of two rigs located in Kazakhstan during the fourth quarter. The net gains for 2013 were primarily the result of long-lived asset sales include the sale of two rigs located in New Zealand, a building located in Tulsa, Oklahoma and a barge rig located in Mexico. Additionally, during the normal course of business we periodically sell equipment deemed to be excess or not currently required for operations.

Interest income and expense

Interest expense decreased $3.6 million to $44.3 million for the year ended December 31, 2014 compared with $47.8 million for the year ended December 31, 2013. This decrease was primarily related to a decrease in debt-related interest expense resulting from lower interest rates on our outstanding debt balance and a lower total debt balance, offset by an increase in amortization of debt issuance costs and a decrease in capitalized interest. Interest income decreased $2.3 million to $0.2 million during the 2014, compared with interest income of $2.5 million during 2013 primarily related to interest earned on an IRS refund received during 2013.

Loss on extinguishment of debt

Loss on extinguishment of debt was $30.2 million and $5.2 million for the years ended December 31, 2014 and December 31, 2013, respectively. The loss on extinguishment of debt for 2014 related to the purchase and redemption of the 9.125% Notes during the first six months of 2014. The loss on extinguishment of debt for 2013 is related to the write-off of debt issuance costs resulting from the repayment of a $125 million term loan, fully funded by Goldman Sachs Bank USA as Sole Lead Arranger and Administrative Agent (Goldman Term Loan) in July 2013.

Other income and expense

Other income and expense was $2.5 million of income and $1.5 million of income for the years ended December 31, 2014 and December 31, 2013, respectively. Other income in 2014 was primarily related to earnings from our investment in an unconsolidated subsidiary that was acquired as part of the ITS Acquisition as well as settlements of claims against a vendor. This income was partially offset by losses related to foreign currency fluctuations from our Sakhalin Island operations. Other income in 2013 was primarily related to the recognition of non-refundable deposits from a buyer in connection with the sale of three rigs for which the sales agreement was terminated in the fourth quarter of 2013.

Income tax expense

Income tax expense was $24.1 million for the year ended December 31, 2014, compared with $25.6 million for the year ended December 31, 2013. The decrease was driven primarily by the decrease in pre-tax income and the mix of operations.

Our effective tax rate was 49.6 percent for the year ended December 31, 2014, compared with 48.5 percent for the year ended December 31, 2013. Our tax rate is affected by recurring items, such as tax rates in state and foreign jurisdictions and the relative amounts of income we earn in those jurisdictions. It is also affected by discrete items, such as return-to-accrual adjustments and changes in reserves for uncertain tax positions, which may occur in any given year but are not consistent from year to year.

Year Ended December 31, 2013 Compared with Year Ended December 31, 2012

Revenues of $874.2 million for the year ended December 31, 2013 increased $196.4 million, or 29.0 percent, from the comparable 2012 period. Operating gross margin increased $16.9 million to $168.4 million for the year ended December 31, 2013 as compared to $151.6 million for the year ended December 31, 2012.

The following is an analysis of our operating results for the comparable periods by reportable segment:

	Year Ended December 31,			
	2013		2012	
Dollars in Thousands				
Revenues:				
Rental Tools	$ 310,041	35%	$ 246,900	36%
U.S. Barge Drilling	136,855	16%	123,672	18%
U.S. Drilling	66,928	8%	1,387	1%
International Drilling	333,962	38%	291,772	43%
Technical Services	26,386	3%	14,030	2%
Construction Contract	—	—%	—	—%
Total revenues	874,172	100%	677,761	100%
Operating gross margin excluding depreciation and amortization:				
Rental Tools	147,017	47%	158,016	64%
U.S Barge Drilling	65,595	48%	54,100	44%
U.S. Drilling	11,901	18%	(8,151)	n/a
International Drilling	71,078	21%	60,492	21%
Technical Services	2,181	8%	116	1%
Construction Contract	4,728	n/a	—	—%
Total operating gross margin excluding depreciation and amortization	302,500	35%	264,573	39%
Depreciation and amortization	(134,053)		(113,017)	
Total operating gross margin	168,447		151,556	
General and administrative expense	(68,025)		(46,257)	
Impairments and other charges	—		—	
Provision for reduction in carrying value of certain assets	(2,544)		—	
Gain on disposition of assets, net	3,994		1,974	
Total operating income	$ 101,872		$ 107,273	

Operating gross margin amounts are reconciled to our most comparable U.S. GAAP measure as follows:

Dollars in Thousands	Rental Tools	U.S. Barge Drilling	U.S. Drilling	International Drilling	Technical Services	Construction Contract[(2)]
Year Ended December 31, 2013						
Operating gross margin[(1)]	$ 91,164	$ 51,257	$ (4,484)	$ 23,732	$ 2,050	$ 4,728
Depreciation and amortization	55,853	14,338	16,385	47,346	131	—
Operating gross margin excluding depreciation and amortization	$ 147,017	$ 65,595	$ 11,901	$ 71,078	$ 2,181	$ 4,728
Year Ended December 31, 2012						
Operating gross margin[(1)]	$ 113,899	$ 39,608	$ (15,168)	$ 13,138	$ 79	$ —
Depreciation and amortization	44,117	14,492	7,017	47,354	37	—
Operating gross margin excluding depreciation and amortization	$ 158,016	$ 54,100	$ (8,151)	$ 60,492	$ 116	$ —

(1) Operating gross margin is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

(2) The Construction Contract segment does not incur depreciation and amortization.

Rental Tools

Rental Tools segment revenues increased $63.1 million, or 25.6 percent, to $310.0 million for the year ended December 31, 2013 compared to $246.9 million for the year ended December 31, 2012. The increase was due to an $86.3 million increase in our international revenues, partially offset by a $23.2 million decrease in our U.S. revenues. The increase in international revenues was primarily due to revenues from ITS, which contributed an increase of $88.0 million of revenues for the year ended December 31, 2013. The decrease in U.S. rental tools revenues was primarily due to the impact of the continuing competitive conditions in the U.S. land drilling market due to declines in drilling activity in almost all major basins, partially offset by higher revenues from a growing participation in the expanding U.S. GOM offshore drilling market.

Rental Tools segment operating gross margin excluding depreciation and amortization decreased $11.0 million, or 7.0 percent, to $147.0 million for the year ended December 31, 2013 as compared with $158.0 million for the year ended December 31, 2012. The decrease was primarily due to a reduction in gross margin excluding depreciation and amortization for our U.S. operations of $29.4 million, primarily due to the increase in competitive conditions which led to lower product pricing for rental tools and related activities and a decline in rental tool utilization. This decrease was partially offset by an increase for our international operations due to the contribution of $20.5 million of gross margin excluding depreciation and amortization attributable to ITS from the date of acquisition.

U.S. Barge Drilling

U.S. Barge Drilling segment revenues increased $13.2 million, or 10.7 percent, to $136.9 million for the year ended December 31, 2013, as compared with revenues of $123.7 million for the year ended December 31, 2012. The increase in revenues was primarily due to an increase in rig fleet utilization and higher average dayrates for the fleet during 2013. Both of these factors reflect a general increase in overall drilling activity in the U.S. GOM inland waters and an increase in our dayrates for multi-well contracts based on our ability to deliver higher levels of performance compared with our competitors.

U.S. Barge Drilling segment operating gross margin excluding depreciation and amortization increased $11.5 million, or 21.2 percent, to $65.6 million for the year ended December 31, 2013, compared with $54.1 million for the year ended December 31, 2012. This increase is primarily a result of improved average dayrates and the continued control of operating costs.

U.S. Drilling

U.S. Drilling segment revenues increased $65.5 million to $66.9 million for the year ended December 31, 2013, compared with $1.4 million for the year ended December 31, 2012. This increase in revenues is primarily due to the commencement of operations by our two arctic-class drilling rigs in Alaska, one in the fourth quarter of 2012 and the other in the first quarter of 2013. Prior to that, during the first three quarters of 2012, both rigs were under construction and not generating revenues. Additionally, in February 2013 we began an O&M contract supporting three platform operations located offshore California.

U.S. Drilling segment operating gross margin excluding depreciation and amortization was $11.9 million for the year ended December 31, 2013 compared with a loss of $8.2 million for the year ended December 31, 2012. The increase in gross margin excluding depreciation and amortization for this segment is mainly due to the contributions from the arctic-class drilling rigs in Alaska and the California O&M contract described above which were not earning revenues or contributing to gross margin during 2012. The loss in 2012 resulted from expenditures associated with re-entering the Alaska market prior to the rigs going to work in Alaska in late 2012 and into early 2013.

International Drilling

International Drilling segment revenues increased $42.2 million, or 14.5 percent, to $334.0 million for the year ended December 31, 2013, compared with $291.8 million for the year ended December 31, 2012. The increase in revenues is primarily due to higher revenues generated by our O&M contracts coupled with higher drilling revenues through the operation of rigs we own.

Revenues related to Parker-owned rigs increased $19.4 million, or 10.6 percent, to $202.9 million for the year ended December 31, 2013 compared with $183.5 million for the year ended December 31, 2012. The increase in revenues was primarily due to the contribution of revenues from a previously idle rig added to our Sakhalin Island operations and two previously idle rigs added to our operations in the Kurdistan Region of Iraq partially offset by lower utilization in Algeria. Additionally, there were increased revenues related to our arctic-class barge rig in the Caspian Sea and the contribution of revenues from a previously idle rig in the Karachaganak field in Kazakhstan.

O&M revenues increased $22.8 million, or 21.1 percent, to $131.1 million, for the year ended December 31, 2013 compared to $108.3 million for the year ended December 31, 2012. The increase in revenues was primarily due to higher reimbursable revenues associated with our services contracts related to the Berkut platform project in South Korea and Orlan platform project on Sakhalin Island. Reimbursable revenues are generated through our purchasing support for the O&M rigs we operate for our customers. Approximately $46.4 million and $31.3 million of O&M revenues were attributable to reimbursable costs for the years ended December 31, 2013 and 2012, respectively. Reimbursable revenues add to revenues but have a minimal impact on operating margins.

International Drilling operating gross margin excluding depreciation and amortization increased $10.6 million, or 17.5 percent, to $71.1 million for the year ended December 31, 2013, compared with $60.5 million for the year ended December 31, 2012. The increase in operating gross margin excluding depreciation and amortization for the year ended December 31, 2013 was from our Parker-owned rig operations slightly offset by a decrease in O&M margins.

Operating gross margin excluding depreciation and amortization related to Parker-owned rigs was $51.0 million and $39.6 million for the years ended December 31, 2013 and 2012, respectively. The increase in operating gross margin excluding depreciation and amortization was primarily due to the contribution of revenues from a previously idle rig in Kazakhstan, in our Karachaganak field operations, and a previously idle rig in our Sakhalin Island operations. Additionally, there were increased revenues from higher utilization of our arctic-class barge rig in the Caspian Sea. The increase was partially offset by costs associated with the mobilization and start-up of the two rigs located in the Kurdistan Region of Iraq, decreased utilization resulting from two Algeria rigs stacked in Tunisia and lower revenues and higher costs in our Latin America region.

Operating gross margin excluding depreciation and amortization generated by our O&M operations was $20.0 million and $20.9 million for the years ended December 31, 2013 and 2012, respectively. The decrease in operating gross margin excluding depreciation and amortization is primarily due to the completion of an O&M contract in China that was active during all of 2012, a decrease in revenues from our Coral Sea project in Papua New Guinea, and higher operating costs related to the Orlan platform project on Sakhalin Island. These decreases were partially offset by an increase in labor revenues related to the Berkut platform project in South Korea.

Technical Services

Technical Services segment revenues increased $12.4 million, or 88.1 percent, to $26.4 million for the year ended December 31, 2013, compared with $14.0 million for the year ended December 31, 2012. This increase was primarily due to increased activity under the vendor services phase of the Berkut platform project which started during the 2012 third quarter and a new customer FEED project that together more than offset the mid-2012 completion of two other customer FEED projects.

Operating gross margin excluding depreciation and amortization for this segment increased by $2.1 million to $2.2 million for the year ended December 31, 2013, compared with nominal gross margin excluding depreciation and amortization for the year ended December 31, 2012. The increase is primarily the result of change in the scope of projects noted above. The Technical Services segment incurs minimal depreciation and amortization which primarily relates to office furniture and fixtures.

Construction Contract

This segment was created for and only includes the Liberty extended-reach drilling rig construction project which our customer canceled in 2011 prior to final completion. Our construction contract segment revenues were zero for the years ended December 31, 2013 and 2012. This segment reported $4.7 million and zero operating gross margin excluding depreciation and amortization for the years ended December 31, 2013 and 2012, respectively. The operating gross margin excluding depreciation and amortization generated during the year ended December 31, 2013 resulted from close-out of the Liberty project.

The Liberty rig construction contract was a fixed-fee and reimbursable contract that we accounted for on a percentage of completion basis. We recognized $335.5 million in revenues and $11.7 million of operating gross margin over the life of the contract. Over the course of the project, we established a project contingency reserve, which we maintained for potential claims by our subcontractors, vendors and customer. Due to the closure of all material claims, for which payments have been made or otherwise resolved or which are barred by the applicable statute of limitations, during the fourth quarter of 2013, we reversed the contingency reserve resulting in the operating gross margin excluding depreciation and amortization recognized for the year ended December 31, 2013.

Other Financial Data

General and administrative expense

General and administrative expense increased $21.8 million to $68.0 million for the year ended December 31, 2013, compared with $46.3 million for the year ended December 31, 2012. The general and administrative expense increase was due primarily to approximately $22.5 million of costs incurred during 2013 related to the ITS Acquisition slightly offset by decreased costs relating to the settlement with the DOJ and SEC, and decreased legal fees associated with the related SEC and DOJ investigations. See Note 13 - Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data for further discussion.

Provision for reduction in carrying value of certain assets

Provision for reduction in carrying value of certain assets was $2.5 million which was comprised of non-cash charges recognized for three rigs reclassified from assets held for sale to assets held and used for which carrying values exceeded fair values. During 2013, management concluded, based on the facts and circumstances at the time, it was no longer probable that the sales of the rigs sale would be consummated.

Gain on disposition of assets

Net gains recorded on asset dispositions for the years ended December 31, 2013 and 2012 were $4.0 million and $2.0 million, respectively. During 2013, we sold two rigs located in New Zealand, a building located in Tulsa and a barge rig located in Mexico. These sales resulted in gains totaling $1.2 million. Additionally, during the normal course of operations, we periodically sell equipment deemed to be excess, obsolete, or not currently required for operations.

Interest income and expense

Interest expense increased $14.3 million to $47.8 million for the year ended December 31, 2013 compared with $33.5 million for the year ended December 31, 2012. The increase in interest expense primarily resulted from an $11.6 million increase in debt-related interest expense primarily related to the full-year impact of the $125.0 million of 9.125% Notes issued in the second quarter of 2012, the $225.0 million 7.50% Notes issued in July 2013 and the $125.0 million debt incurred in April 2013 used to initially fund the ITS Acquisition. Additionally, we experienced a $7.9 million decrease in interest capitalized on internal construction projects resulting from the completion of the two arctic-class drilling rigs in Alaska, which increased overall interest expense. The increase in interest expense is partially offset by a decrease due to the repayment of our 2.125% Convertible Notes in the 2013 second quarter and a decrease in amortization of debt issuance costs. Interest income was $2.5 million and $0.2 million for the years ended December 31, 2013 and 2012, respectively. Interest income in 2013 primarily related to interest earned on an IRS refund received during the year.

Loss on extinguishment of debt

Loss on extinguishment of debt was $5.2 million and $2.1 million for the years ended December 31, 2013 and December 31, 2012, respectively. The loss on extinguishment of debt for 2013 is related to the extinguishment in July 2013 of the $125 million debt incurred in April 2013 used to initially fund the ITS Acquisition. The loss on extinguishment of debt for 2012 resulted from the repurchase of $122.9 million of outstanding 2.125% Convertible Notes in May 2012.

Other income and expense

Other income and expense was $1.5 million of income and $0.8 million of expense for the years ended December 31, 2013 and December 31, 2012, respectively. Other income in 2013 was primarily related to the recognition of non-refundable deposits from a buyer in connection with the sale of three rigs for which the sales agreement was terminated in the 2013 fourth quarter.

Income tax expense

Income tax expense was $25.6 million for the year ended December 31, 2013, compared with $33.9 million for the year ended December 31, 2012. The 2013 tax expense decrease was primarily due to lower pre-tax earnings in addition to discrete items relating to enactment of new tax legislation in Mexico, research and development tax credits and other less significant items related to return-to-accrual adjustments.

Our effective tax rate was 48.5% for the year ended December 31, 2013, compared with 47.7% for the year ended December 31, 2012. Our tax rate is affected by recurring items, such as tax rates in state and non-U.S. jurisdictions and the relative amounts of income we earn in those jurisdictions, which we expect to be fairly consistent in the near term. It is also affected by discrete items, such as return-to-accrual adjustments and changes in reserves for uncertain tax positions, which may occur in any given year but are not consistent from year to year.

Liquidity and Capital Resources

We periodically evaluate our liability requirements, capital needs and availability of resources in view of expansion plans, debt service requirements, and other operational cash needs. To meet our short and long term liquidity requirements, including payment of operating expenses and repaying debt, we rely primarily on cash from operations. When determined necessary we may seek to raise additional capital in the future. We expect that for the foreseeable future, cash on hand and cash generated from operations will be sufficient to provide us the ability to fund our operations, provide the working capital necessary to support our strategy, and fund planned capital expenditures. We do not pay dividends to our shareholders.

Subsequent to December 31, 2014, we increased our liquidity by entering into the 2015 Secured Credit Agreement on January 26, 2015. This agreement amends and restates the Amended and Restated Credit Agreement (the 2012 Secured Credit Agreement) dated December 14, 2012. The 2015 Secured Credit Agreement is comprised of a $200 million revolving credit facility. The 2012 Secured Credit Agreement consisted of an $80 million revolving credit facility and a $50 million term loan facility (Term Loan). At the closing of the 2015 Secured Credit Agreement we repaid $30.0 million of Term Loan borrowings under the 2012 Secured Credit Agreement with a $30.0 million draw under the 2015 Secured Credit Agreement. At the closing, there were no borrowings under the revolving credit portion of the 2012 Secured Credit Agreement.

Cash Flow Activity

As of December 31, 2014, we had cash and cash equivalents of $108.5 million, a decrease of $40.2 million from cash and cash equivalents of $148.7 million at December 31, 2013. The following table provides a summary of our cash flow activity for the last three years:

Dollars in thousands	2014	2013	2012
Operating Activities	$ 202,467	$ 161,497	$ 189,699
Investing Activities	(173,575)	(265,418)	(187,606)
Financing Activities	(69,125)	164,724	(12,076)
Net change in cash and cash equivalents	$ (40,233)	$ 60,803	$ (9,983)

Operating Activities

Cash flows provided by operating activities were $202.5 million in 2014, compared with $161.5 million in 2013. Changes in working capital during 2014 were a use of cash of $17.1 million and a use of cash of $34.0 million for the years ended December 31, 2014 and December 31, 2013, respectively. Over the past few years we have reinvested a substantial portion of our operating cash flows to expand our business through acquisition and to enhance our fleet of drilling rigs and rental tools equipment. It is our intention to continue to utilize our operating cash flows to finance further investments into our rental tools inventories, rig purchases or upgrades as well as other strategic investments aligned with our strategies.

Cash flows provided by operating activities were $161.5 million in 2013 and were impacted by our earnings and by non-cash charges such as depreciation expense, gains on asset sales, deferred tax benefit, stock compensation expense, debt extinguishment and amortization of debt issuance costs. Depreciation expense increased due to our two Alaska rigs commencing work in late 2012 and early 2013. Additionally, during 2013, we more aggressively disposed of assets deemed not core to the current strategy resulting in an increase in gain on disposition of assets. Uses of working capital during 2013 primarily related to the ITS Acquisition which resulted in increased receivables, inventory and accounts payable.

Cash flows provided by operating activities were $189.7 million in 2012. Before changes in operating assets and liabilities, cash from operating activities was impacted primarily by net income of $37.1 million plus non-cash charges of $151.6 million. Non-cash charges primarily consisted of $113.0 million of depreciation expense and deferred tax benefit of $15.8 million.

Investing Activities

Cash flows used in investing activities were $173.6 million for 2014, compared with $265.4 million for 2013. Our primary use of cash during 2014 was capital expenditures of $179.5 million. Capital expenditures were primarily for tubular and other products for our rental tools business and rig-related enhancements and maintenance.

Cash flows used in investing activities were $265.4 million for 2013. Our primary use of cash during 2013 was $118.0 million for the ITS Acquisition and $155.6 million for capital expenditures. Capital expenditures in 2013 were primarily for tubular and other products for our rental tools business, rig-related enhancements and maintenance and costs related to our new enterprise resource planning system. Sources of cash included $8.2 million of proceeds from asset sales.

Cash flows used in investing activities were $187.6 million for 2012. Our primary use of cash was $191.5 million for capital expenditures. Capital expenditures in 2012 were primarily for the construction of our two arctic-class drilling rigs, tubular and other products for our rental tools business, and costs related to our new enterprise resource planning system. In addition, we incurred capital to support ongoing drilling activities. Sources of cash included $3.9 million of proceeds from asset sales.

Capital expenditures for 2015 are estimated to range from $100.0 million to $120.0 million and will primarily be directed to our Rental Tools segment inventory and maintenance capital on our rigs. Any discretionary spending will be evaluated based upon adequate return requirements and available liquidity.

Financing Activities

Cash flows used in financing activities were $69.1 million for 2014. Cash flows used in financing activities primarily related to the repayment of $425.0 million of our 9.125% Notes, payment of $26.2 million of related tender and consent premiums, and payment of debt issuance costs of $7.6 million. Cash provided by financing activities included proceeds of $360.0 million from the issuance of our 6.75% Notes and reborrowing of a $40.0 million Term Loan under our 2012 Secured Credit Agreement.

Cash flows provided by financing activities for 2013 were $164.7 million. Cash flows provided by financing activities primarily related to the $125 million Goldman Term Loan issued during the 2013 second quarter in connection with the ITS Acquisition and the $225.0 million 7.50% Notes issued during the 2013 third quarter. Cash used in financing activities included pay-off of the Goldman Term Loan in the 2013 third quarter, principal payments made under our Term Loan and payments of debt issuance costs.

Cash flows used in financing activities were $12.1 million for 2012. Our primary financing activities included the repayment of $125.0 million of 2.125% Convertible Notes and $18.0 million in quarterly payments against our Term Loan then-outstanding. In addition, we received proceeds from the issuance of an additional $125.0 million aggregate principal amount of 9.125% Notes at a price of 104.0 percent, resulting in gross proceeds of $130.0 million, less $4.9 million of associated debt issuance costs. We also made a $7.0 million draw on our revolving credit facility.

Long-Term Debt Summary

Our principal amount of long-term debt, including current portion, was $615.0 million as of December 31, 2014, which consisted of:

- $360.0 million aggregate principal amount of 6.75% Notes;
- $225.0 million aggregate principal amount of 7.50% Notes; and
- $30.0 million under our Term Loan, $10.0 million of which was classified as current.

6.75% Senior Notes, due July 2022

On January 22, 2014, we issued $360.0 million aggregate principal amount of the 6.75% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 6.75% Notes offering plus a $40.0 million Term Loan draw under the 2012 Secured Credit Agreement and cash on hand were utilized to purchase $416.2 million aggregate principal amount of our outstanding 9.125% Senior Notes due 2018 pursuant to a tender and consent solicitation offer commenced on January 7, 2014. See further discussion of the tender and consent solicitation offer below entitled "*9.125% Senior Notes, due April 2018*".

The 6.75% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 6.75% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the 2015 Secured Credit Agreement and our 7.50% Notes. Interest on the 6.75% Notes is payable on January 15 and July 15 of each year, beginning July 15, 2014. Debt issuance costs related to the 6.75% Notes of approximately $7.6 million ($7.0 million net of amortization as of December 31, 2014) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to January 15, 2017, we may redeem up to 35 percent of the aggregate principal amount of the 6.75% Notes at a redemption price of 106.75 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after January 15, 2018, we may redeem all or a part of the 6.75% Notes upon appropriate notice, at a redemption price of 103.375 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning January 15, 2020. If we experience certain changes in control, we must offer to repurchase the 6.75% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as events of default. These covenants are subject to a number of important exceptions and qualifications.

7.50% Senior Notes, due August 2020

On July 30, 2013, we issued $225.0 million aggregate principal amount of the 7.50% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 7.50% Notes offering were primarily used to repay the $125.0 million aggregate principal amount of the Goldman Term Loan, to repay $45.0 million of Term Loan borrowings and for general corporate purposes.

The 7.50% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 7.50% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the 2015 Secured Credit Agreement and the 6.75% Notes. Interest on the 7.50% Notes is payable on February 1 and August 1 of each year, beginning February 1, 2014. Debt issuance costs related to the 7.50% Notes of approximately $5.6 million ($4.7 million, net of amortization as of December 31, 2014) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to August 1, 2016, we may redeem up to 35 percent of the aggregate principal amount of the 7.50% Notes at a redemption price of 107.50 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after August 1, 2016, we may redeem all or a part of the 7.50% Notes upon appropriate notice, at a redemption price of 103.750 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning August 1, 2018. If we experience certain changes in control, we must offer to repurchase the 7.50% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as events of default. These covenants are subject to a number of important exceptions and qualifications.

9.125% Senior Notes, due April 2018

On March 22, 2010, we issued $300.0 million aggregate principal amount of the 9.125% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 9.125% Notes offering were primarily used to redeem the $225.0 million aggregate principal amount of our 9.625% Senior Notes due 2013 and to repay $42.0 million of borrowings under our senior secured revolving credit facility.

On April 25, 2012, we issued an additional $125.0 million aggregate principal amount of 9.125% Notes under the same indenture at a price of 104.0% of par, resulting in gross proceeds of $130.0 million. Net proceeds from the offering were utilized to refinance $125.0 million aggregate principal amount of the 2.125% Convertible Senior Notes due July 2012.

On January 7, 2014, we commenced a tender and consent solicitation with respect to the 9.125% Notes. The tender offer price was $1,061.98, inclusive of a $30.00 consent payment, for each $1,000 principal amount of 9.125% Notes, plus accrued and unpaid interest. On January 22, 2014, we paid $453.7 million for the tendered 9.125% Notes, comprised of $416.2 million of aggregate principal amount of the 9.125% Notes, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. On April 1, 2014, we redeemed the remaining $8.8 million aggregate principal amount of the outstanding 9.125% Notes for a purchase price of $9.6 million, inclusive of a $0.4 million call premium and $0.4 million interest. During the year ended December 31, 2014, we recorded a loss on extinguishment of debt of approximately $30.2 million, which included the tender and consent premiums of $25.8 million, the call premium of $0.4 million and the write-off of unamortized debt issuance costs of $7.7 million, offset by the write-off of the remaining unamortized debt issuance premium of $3.8 million.

2015 Secured Credit Agreement

On January 26, 2015 we entered into the 2015 Secured Credit Agreement, which amended and restated the 2012 Secured Credit Agreement. The 2015 Secured Credit Agreement is comprised of a $200 million revolving credit facility (2015 Revolver). The 2012 Secured Credit Agreement consisted of an $80 million revolving credit facility and a $50 million Term Loan. At the closing of the 2015 Secured Credit Agreement, we repaid $30.0 million of Term Loan borrowings under the 2012 Secured Credit Agreement with a $30.0 million draw under the 2015 Revolver. At the closing date there were no borrowings under the revolving credit portion of the 2012 Secured Credit Agreement.

Our 2015 Revolver is available for general corporate purposes and to support letters of credit. Interest on 2015 Revolver loans accrues at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. Under the 2015 Secured Credit Agreement, the Applicable Rate varies from a rate per annum ranging from 2.50 percent to 3.00 percent for LIBOR rate loans and 1.50 percent to 2.00 percent for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the 2015 Secured Credit Agreement). Revolving loans are available subject to a quarterly Asset Coverage Ratio calculation based on the Orderly Liquidation Value of certain specified rigs including barge rigs in the Gulf of Mexico and land rigs in Alaska, and rental equipment of the Company and its subsidiary guarantors and a percentage of eligible domestic accounts receivable. Upon closing of the 2015 Secured Credit Agreement, there was $30.0 million drawn on the 2015 Revolver and $11.7 million of letters of credit outstanding. The 2015 Secured Credit Agreement matures on January 26, 2020.

2012 Secured Credit Agreement

On December 14, 2012, we entered into the 2012 Secured Credit Agreement consisting of a senior secured $80.0 million revolving facility (2012 Revolver) and the Term Loan. In July 2013, the 2012 Secured Credit Agreement was amended to permit re-borrowing in the form of additional term loans, of up to $45.0 million, decreasing by $2.5 million at the end of each quarter beginning September 30, 2013 and ending March 31, 2014. In January 2014 we re-borrowed $40 million of the Term Loan.

Our obligations under the 2012 Secured Credit Agreement were guaranteed by substantially all of our direct and indirect domestic subsidiaries other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States, each of which have executed guaranty agreements, and were secured by first priority liens on our accounts receivable, specified barge rigs and rental equipment. The 2012 Secured Credit Agreement contained customary affirmative and negative covenants with which we were in compliance as of December 31, 2014 and December 31, 2013. The 2012 Secured Credit Agreement would have matured on December 14, 2017.

2012 Revolver

Our 2012 Revolver was available for general corporate purposes and to support letters of credit. Interest on Revolver loans accrued at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. Under the 2012 Secured Credit Agreement, the Applicable Rate varied from a rate per annum ranging from 2.50 percent to 3.00 percent for LIBOR rate loans and 1.50 percent to 2.00 percent for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the 2012 Secured Credit Agreement). Revolving loans were available subject to an asset coverage ratio determined based on a percentage of eligible accounts receivable, certain specified barge drilling rigs and rental equipment of the Company and its subsidiary guarantors. There were no revolving loans outstanding at December 31, 2014 and December 31, 2013. Letters of credit outstanding as of December 31, 2014 and December 31, 2013 totaled $11.0 million and $4.6 million, respectively.

Term Loan

The Term Loan originated at $50.0 million on December 14, 2012 and required quarterly principal payments of $2.5 million, which began March 31, 2013. Interest on the Term Loan accrued at a Base Rate plus 2.00 percent or LIBOR plus 3.00 percent. The outstanding balance on the Term Loan at December 31, 2013 was zero. In January 2014 we re-borrowed $40 million of the Term Loan and used the proceeds, along with the proceeds from the issuance of the 6.75% Notes, to repurchase our 9.125% Notes. As of December 31, 2014 the remaining balance on the Term Loan was $30.0 million. At the closing of the 2015 Secured Credit Agreement, we repaid $30.0 million of Term Loan borrowings under the 2012 Secured Credit Agreement with a $30.0 million draw under the 2015 Revolver.

Liquidity

As of December 31, 2014, we had approximately $177.5 million of liquidity, which consisted of $108.5 million of cash and cash equivalents on hand and $69.0 million of availability under the 2012 Revolver.

We do not have any unconsolidated special-purpose entities, off-balance sheet financing arrangements or guarantees of third-party financial obligations. As of December 31, 2014 we have no energy, commodity, or foreign currency derivative contracts.

The following table summarizes our future contractual cash obligations as of December 31, 2014:

	Total	Less than 1 Year	Years 1 - 3	Years 3 - 5	More than 5 Years
			(Dollars in Thousands)		
Contractual cash obligations:					
Long-term debt — principal	$ 615,000	$ 10,000	$ 20,000	$ —	$ 585,000
Long-term debt — interest	297,216	42,018	83,073	82,350	89,775
Operating leases(1)	47,657	13,188	15,649	10,361	8,459
Purchase commitments(2)	65,195	65,195	—	—	—
Total contractual obligations	$ 1,025,068	$ 130,401	$ 118,722	$ 92,711	$ 683,234
Commercial commitments:					
Standby letters of credit(3)	10,999	10,999	—	—	—
Total commercial commitments	$ 10,999	$ 10,999	$ —	$ —	$ —

1) Operating leases consist of lease agreements in excess of one year for office space, equipment, vehicles and personal property.

2) We had purchase commitments outstanding as of December 31, 2014, related to rental tools and rig upgrade projects.

3) We had an $80.0 million Revolver pursuant to our 2012 Secured Credit Agreement. As of December 31, 2014, $11.0 million of availability under the 2012 Revolver had been used to support letters of credit that had been issued.

With the closing of the 2015 Secured Credit Agreement disclosed above, we improved our liquidity, which consisted of current cash and cash equivalents on hand and $158.3 million of availability under the 2015 Revolver. At closing, a $30.0 million loan was borrowed from the 2015 Revolver, the Term Loan was paid with the borrowings and all outstanding letters of credit of $11.7 million were continued.

Other Matters

Business Risks

See Item 1A. Risk Factors, for a discussion of risks related to our business.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, we evaluate our estimates, including those related to fair value of assets, bad debt, materials and supplies obsolescence, property and equipment, goodwill, income taxes, workers' compensation and health insurance and contingent liabilities for which settlement is deemed to be probable. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. While we believe that such estimates are reasonable, actual results could differ from these estimates.

We believe the following are our most critical accounting policies as they can be complex and require significant judgments, assumptions and/or estimates in the preparation of our consolidated financial statements. Other significant accounting policies are summarized in Note 1 in the notes to the consolidated financial statements.

Fair value measurements. For purposes of recording fair value adjustments for certain financial and non-financial assets and liabilities, and determining fair value disclosures, we estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation technique requires inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows: (1) unadjusted quoted prices for identical assets or liabilities in active markets (Level 1), (2) direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets (Level 2) and (3) unobservable inputs that require significant judgment for which there is little or no market data (Level 3). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Impairment of Property, Plant and Equipment. We review the carrying amounts of long-lived assets for potential impairment when events occur or circumstances change that indicate the carrying values of such assets may not be recoverable. For example, evaluations are performed when we experience sustained significant declines in utilization and dayrates, and we do not contemplate recovery in the near future. In addition, we evaluate our assets when we reclassify property and equipment to assets held for sale or as discontinued operations as prescribed by accounting guidance related to accounting for the impairment or disposal of long-lived assets. We determine recoverability by evaluating the undiscounted estimated future net cash flows. When impairment is indicated, we measure the impairment as the amount by which the assets carrying value exceeds its fair value. Management considers a number of factors such as estimated future cash flows, appraisals and current market value analysis in determining fair value. Assets are written down to fair value if the concluded current fair value is below the net carrying value.

Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates and costs. The use of different estimates and assumptions could result in materially different carrying values of our assets.

Accrual for Self-Insurance. Substantially all of our operations are subject to hazards that are customary for oil and natural gas drilling operations, including blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, oil and natural gas well fires and explosions, natural disasters, pollution, mechanical failure and damage or loss during transportation. Some of our fleet is also subject to hazards inherent in marine operations, either while on-site or during mobilization, such as capsizing, sinking, grounding, collision, damage from severe weather and marine life infestations. These hazards could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. We have had accidents in the past due to some of these hazards.

Our contracts provide for varying levels of indemnification between ourselves and our customers, including with respect to well control and subsurface risks. We seek to obtain indemnification from our customers by contract for certain of these risks. We also maintain insurance for personal injuries, damage to or loss of equipment and other insurance coverage for various business risks. To the extent that we are unable to transfer such risks to customers by contract or indemnification agreements, we seek protection through insurance. However, these insurance or indemnification agreements may not adequately protect us against liability from all of the consequences of the hazards described above. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of an insurance coverage deductible.

Based on the risks discussed above, we estimate our liability in excess of insurance coverage and accrue for these amounts in our consolidated financial statements. Accruals related to insurance are based on the facts and circumstances specific to the insurance claims and our past experience with similar claims. The actual outcome of insured claims could differ significantly from the amounts estimated. We accrue actuarially determined amounts in our consolidated balance sheet to cover self-insurance retentions for workers' compensation, employers' liability, general liability, automobile liability and health benefits claims. These accruals use historical data based upon actual claim settlements and reported claims to project future losses. These estimates and accruals have historically been reasonable in light of the actual amount of claims paid.

As the determination of our liability for insurance claims could be material and is subject to significant management judgment and in certain instances is based on actuarially estimated and calculated amounts, management believes that accounting estimates related to insurance accruals are critical.

Accounting for Income Taxes. We are a U.S. company and we operate through our various foreign legal entities and their branches and subsidiaries in numerous countries throughout the world. Consequently, our tax provision is based upon the tax laws and rates in effect in the countries in which our operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary. Therefore, as a part of the process of preparing the consolidated financial statements, we are required to estimate the income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes. Our effective tax rate for financial statement purposes will continue to fluctuate from year to year as our operations are conducted in different taxing jurisdictions. Current income tax expense represents either liabilities expected to be reflected on our income tax returns for the current year, nonresident withholding taxes or changes in prior year tax estimates which may result from tax audit adjustments. Our deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported on the consolidated balance sheet. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In order to determine the amount of deferred tax assets or liabilities, as well as the valuation allowances, we must make estimates and assumptions regarding future taxable income, where rigs will be deployed and other matters. Changes in these estimates and assumptions, as well as changes in tax laws, could require us to adjust the deferred tax assets and liabilities or valuation allowances, including as discussed below.

Our ability to realize the benefit of our deferred tax assets requires that we achieve certain future earnings levels prior to the expiration of our net operating loss (NOL) and foreign tax credit (FTC) carryforwards. In the event that our earnings performance projections do not indicate that we will be able to benefit from our NOL and FTC carryforwards, valuation allowances are established following the "more likely than not" criteria. We periodically evaluate our ability to utilize our NOL and FTC carryforwards and, in accordance with accounting guidance related to accounting for income taxes, will record any resulting adjustments that may be required to deferred income tax expense in the period for which an existing estimate changes.

We do not currently provide for U.S. deferred taxes on unremitted earnings of our foreign subsidiaries as such earnings are deemed to be permanently reinvested. If such earnings were to be distributed, we could be subject to U.S. taxes, which may have a material impact on our results of operations. We cannot practically estimate the amount of additional taxes that might be payable on unremitted earnings. We annually review our position and may elect to change our future tax position.

We apply the accounting standards related to uncertainty in income taxes. This accounting guidance requires that management make estimates and assumptions affecting amounts recorded as liabilities and related disclosures due to the uncertainty as to final resolution of certain tax matters. Because the recognition of liabilities under this interpretation may require periodic adjustments and may not necessarily imply any change in management's assessment of the ultimate outcome of these items, the amount recorded may not accurately reflect actual outcomes.

Revenue Recognition. Contract drilling revenues and expenses, comprised of daywork drilling contracts, call-outs against master service agreements and engineering and related project service contracts, are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment. Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized over the term of the related drilling contract; however, costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs. For contracts that are terminated prior to the specified term, early termination payments received by us are recognized as revenues when all contractual requirements are met. Revenues from rental activities are recognized ratably over the rental term which is generally less than six months. Technical Services contracts include engineering, consulting, and project management scopes of work and revenue is typically recognized on a time and materials basis.

Allowance for Doubtful Accounts — The allowance for doubtful accounts is estimated for losses that may occur resulting from disputed amounts and the inability of our customers to pay amounts owed. We estimate the allowance based on historical write-off experience and information about specific customers. We review individually, for collectability, all balances over 90 days past due as well as balances due from any customer with respect to which we have information leading us to believe that a risk exists for potential collection.

Legal and Investigation Matters - As of December 31, 2014, we have accrued an estimate of the probable and estimable costs for the resolution of certain legal and investigation matters. We have not accrued any amounts for other matters for which the liability is not probable and reasonably estimable. Generally, the estimate of probable costs related to these matters is developed in consultation with our legal advisors. The estimates take into consideration factors such as the complexity of the issues, litigation risks and settlement costs. If the actual settlement costs, final judgments, or fines, after appeals, differ from our estimates, our future financial results may be adversely affected.

Recent Accounting Pronouncements

For a discussion of the new accounting pronouncements that have had or are expected to have an effect on our consolidated financial statements, see Note 18 - Recent Accounting Pronouncements in the Notes to the Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Foreign Currency Exchange Rate Risk

Our international operations expose us to foreign currency exchange rate risk. There are a variety of techniques to minimize the exposure to foreign currency exchange rate risk, including customer contract payment terms and the possible use of foreign currency exchange rate risk derivative instruments. Our primary foreign currency exchange rate risk management strategy involves structuring customer contracts to provide for payment in both U.S. dollars and local currency. The payment portion denominated in local currency is based on anticipated local currency requirements over the contract term. Due to various factors, including customer acceptance, local banking laws, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual foreign currency exchange rate risk needs may vary from those anticipated in the customer contracts, resulting in partial exposure to foreign exchange risk. Fluctuations in foreign currencies typically have not had a material impact on our overall results. In situations where payments of local currency do not equal local currency requirements, foreign currency exchange rate risk derivative instruments, specifically spot purchases, may be used to mitigate foreign exchange rate currency risk. We do not enter into derivative transactions for speculative purposes. At December 31, 2014, we had no open foreign currency exchange rate risk derivative contracts.

Interest Rate Risk

We are exposed to changes in interest rates through our fixed rate long-term debt. Typically, the fair market value of fixed rate long-term debt will increase as prevailing interest rates decrease and will decrease as prevailing interest rates increase. The fair value of our long-term debt is estimated based on quoted market prices where applicable, or based on the present value of expected cash flows relating to the debt discounted at rates currently available to us for long-term borrowings with similar terms and maturities. The estimated fair value of our $360.0 million principal amount of 6.75% Notes, based on quoted market prices, was $270.0 million at December 31, 2014. The estimated fair value of our $225.0 million principal amount of 7.50% Notes, based on quoted market prices, was $180.0 million at December 31, 2014. A hypothetical 100 basis point increase in interest rates relative to market interest rates at December 31, 2014 would decrease the fair market value of our 6.75% Notes by approximately $27.0 million and decrease the fair market value of our 7.50% Notes by approximately $17.3 million.

In 2011, we entered into two variable-to-fixed interest rate swap agreements as a strategy to manage the floating rate risk on the Term Loan borrowings under the then-effective secured credit agreement. The two agreements fixed the interest rate on a notional amount of $73.0 million of borrowings at 3.878 percent for the period beginning June 27, 2011 and terminating May 14, 2013. The notional amount of the swap agreements decreased correspondingly with amortization of the Term Loan. We did not apply hedge accounting to the agreements and, accordingly, reported the mark-to-market change in the fair value of the interest rate swaps in earnings. As of December 31, 2013 the swap agreements had expired and as of December 31, 2012, the fair value of the interest rate swap was a liability of $0.1 million.

Impact of Fluctuating Commodity Prices

We are exposed to the impact of fluctuations in market prices for oil and natural gas affecting spending by E&P companies on drilling programs. In the past, steep, prolonged and unexpected price reductions in oil prices have led to significant reductions in drilling activity for the related commodity. This usually does not result in cancellations of existing contracts for our rigs and rental tools, but rather in fewer opportunities to reengage our equipment when contracted work was completed. At those times, drilling rig and rental tools utilization declined along with associated dayrates and rental rates.

In response to the recent steep and swift decline in market prices for oil, and the continued decline in the U.S. price for natural gas, some E&P companies curtailed U.S. drilling activity in the last months of 2014 and many E&P companies have cut 2015 worldwide spending plans to below the prior year's level. This has led to a reduction in activity in the U.S. land and GOM inland waters drilling markets. In addition, many international markets are susceptible to reductions in drilling activity, depending on the depth and duration of the current decline in oil prices.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Parker Drilling Company:

We have audited Parker Drilling Company's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Parker Drilling Company'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 Annual Report on Internal Control over Financial Reporting* in Item 9A. Our responsibility is to express an opinion on Parker Drilling 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, Parker Drilling Company 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 (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Parker Drilling Company and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 25, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Parker Drilling Company:

We have audited the accompanying consolidated balance sheets of Parker Drilling Company and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II - Valuation and Qualifying Accounts. These consolidated financial statements and financial statement schedules are the responsibility of the Parker Drilling 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 Parker Drilling Company 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. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Parker Drilling Company's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 25, 2015 expressed an unqualified opinion on the effectiveness of Parker Drilling Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 25, 2015

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS
(Dollars in Thousands, Except Per Share Data)

	Year Ended December 31,		
	2014	2013	2012
Revenues	$ 968,684	$ 874,172	$ 677,761
Expenses:			
Operating expenses	669,381	571,672	413,188
Depreciation and amortization	145,121	134,053	113,017
	814,502	705,725	526,205
Total operating gross margin	154,182	168,447	151,556
General and administration expense	(35,016)	(68,025)	(46,257)
Provision for reduction in carrying value of certain assets	—	(2,544)	—
Gain on disposition of assets, net	1,054	3,994	1,974
Total operating income	120,220	101,872	107,273
Other income and (expense):			
Interest expense	(44,265)	(47,820)	(33,542)
Interest income	195	2,450	153
Loss on extinguishment of debt	(30,152)	(5,218)	(2,130)
Change in fair value of derivative positions	—	53	55
Other	2,539	1,450	(832)
Total other expense	(71,683)	(49,085)	(36,296)
Income before income taxes	48,537	52,787	70,977
Income tax expense:			
Current tax expense	22,567	12,909	18,042
Deferred tax expense	1,509	12,699	15,837
Total income tax expense	24,076	25,608	33,879
Net income	24,461	27,179	37,098
Less: Net Income (loss) attributable to noncontrolling interest	1,010	164	(215)
Net income attributable to controlling interest	$ 23,451	$ 27,015	$ 37,313
Basic earnings per share:	$ 0.19	$ 0.23	$ 0.32
Diluted earnings per share:	$ 0.19	$ 0.22	$ 0.31
Number of common shares used in computing earnings per share:			
Basic	121,186,464	119,284,468	117,721,135
Diluted	123,076,648	121,224,550	119,093,590

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)

	Year Ended December 31,		
	2014	**2013**	**2012**
Comprehensive income:			
Net income	$ 24,461	$ 27,179	$ 37,098
Other comprehensive gain (loss), net of tax:			
Currency translation difference on related borrowings	(4,870)	(1,525)	—
Currency translation difference on foreign currency net investments	2,147	3,051	—
Total other comprehensive gain (loss), net of tax:	(2,723)	1,526	—
Comprehensive income	21,738	28,705	37,098
Comprehensive (income) loss attributable to noncontrolling interest	(673)	198	215
Comprehensive income (loss) attributable to controlling interest	$ 21,065	$ 28,903	$ 37,313

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(Dollars in Thousands)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 108,456	$ 148,689
Accounts and Notes Receivable, net of allowance for bad debts of $11,188 in 2014 and $12,853 in 2013	270,952	257,889
Rig materials and supplies	47,943	41,781
Deferred costs	5,673	13,682
Deferred income taxes	7,476	9,940
Other tax assets	10,723	24,079
Other current assets	18,556	23,223
Total current assets	469,779	519,283
Property, plant and equipment, net of accumulated depreciation of $1,201,058 in 2014 and $1,136,024 in 2013 (Note 4)	895,940	871,356
Rig materials and supplies	6,937	10,221
Debt issuance costs	12,526	14,208
Deferred income taxes	122,689	102,420
Other assets	12,788	17,268
Total assets	$ 1,520,659	$ 1,534,756
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 10,000	$ 25,000
Accounts payable	78,776	90,033
Accrued liabilities	75,703	84,853
Accrued income taxes	14,186	7,266
Total current liabilities	178,665	207,152
Long-term debt	605,000	628,781
Other long-term liabilities	18,665	26,914
Long-term deferred tax liability	52,115	38,767
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Preferred Stock, $1 par value, 1,942,000 shares authorized, no shares outstanding	—	—
Common Stock, $0.16 2/3 par value, authorized 280,000,000 shares, issued and outstanding, 122,045,877 shares (120,491,164 shares in 2013)	20,325	20,075
Capital in excess of par value	666,769	657,349
Accumulated deficit	(24,165)	(47,616)
Accumulated Other Comprehensive Income	(498)	1,888
Total controlling interest stockholders' equity	662,431	631,696
Noncontrolling interest	3,783	1,446
Total equity	666,214	633,142
Total liabilities and stockholders' equity	$ 1,520,659	$ 1,534,756

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2014	**2013**	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 24,461	$ 27,179	$ 37,098
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	145,121	134,053	113,017
Loss on extinguishment of debt	30,152	5,218	2,130
Gain on disposition of assets	(1,054)	(3,994)	(1,974)
Deferred tax expense	1,509	12,699	15,837
Provision for reduction in carrying value of certain assets	—	2,544	—
Expenses not requiring cash	19,331	17,764	22,600
Change in assets and liabilities:			
Accounts and notes receivable	(12,238)	(33,512)	15,241
Rig materials and supplies	(2,878)	1,754	344
Other current assets	26,032	(11,715)	(4,313)
Accounts payable and accrued liabilities	27,231	(286)	(2,657)
Accrued income taxes	(7,657)	10,454	(6,102)
Other assets	(47,543)	(661)	(1,522)
Net cash provided by operating activities	202,467	161,497	189,699
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(179,513)	(155,645)	(191,543)
Proceeds from the sale of assets	5,938	8,218	3,937
Acquisition of ITS, net of cash acquired	—	(117,991)	
Net cash used in investing activities	(173,575)	(265,418)	(187,606)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	400,000	350,000	130,000
Proceeds from draw on revolver credit facility	—	—	7,000
Repayments of long-term debt	(425,000)	(125,000)	—
Repayments of senior notes	—	—	(125,000)
Repayments of term loan	(10,000)	(50,000)	(18,000)
Payments of debt issuance costs	(7,630)	(11,172)	(4,859)
Payments of debt extinguishment costs	(26,214)	—	(555)
Excess tax benefit (expense) from stock-based compensation	(281)	896	(662)
Net cash provided by (used in) financing activities	(69,125)	164,724	(12,076)
Net increase (decrease) in cash and cash equivalents	(40,233)	60,803	(9,983)
Cash and cash equivalents at beginning of year	148,689	87,886	97,869
Cash and cash equivalents at end of year	108,456	148,689	87,886
Supplemental cash flow information:			
Interest paid	41,820	42,236	37,405
Income taxes paid	26,694	17,036	40,234

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(Dollars and Shares in Thousands)

	Shares	Common Stock	Treasury Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Controlling Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
Balances, December 31, 2011	117,061	$ 19,789	$ (281)	$ 637,042	$ (111,944)	—	$ 544,606	(556)	$ 544,050
Activity in employees' stock plans	1,907	264	46	2,620	—	—	2,930	—	2,930
Tax benefit increase from stock based compensation	—	—	—	$ (662)	—	—	$ (662)	—	$ (662)
Amortization of stock-based awards	—	—	—	7,217	—	—	7,217	—	7,217
Comprehensive Income:									
Net income	—	—	—	—	37,313	—	37,313	(215)	37,098
Balances, December 31, 2012	118,968	$ 20,053	$ (235)	$ 646,217	$ (74,631)	$ —	$ 591,404	$ (771)	$ 590,633
Activity in employees' stock plans	1,523	215	42	805	—	—	1,062	—	1,062
Tax benefit decrease from stock based compensation	—	—	—	896	—	—	896	—	896
Amortization of stock-based awards	—	—	—	9,431	—	—	9,431	—	9,431
Fair value of acquired noncontrolling interest	—	—	—	—	—	—	—	2,680	2,680
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(265)	(265)
Comprehensive Income:									
Net income	—	—	—	—	27,015	—	27,015	164	27,179
Other comprehensive income (loss)	—	—	—	—	—	1,888	1,888	(362)	1,526
Balances, December 31, 2013	120,491	$ 20,268	$ (193)	$ 657,349	$ (47,616)	$ 1,888	$ 631,696	$ 1,446	$ 633,142
Activity in employees' stock plans	1,555	227	23	924	—	—	1,174	—	1,174
Tax benefit increase from stock based compensation	—	—	—	(281)	—	—	(281)	—	(281)
Amortization of stock-based awards	—	—	—	9,273	—	—	9,273	—	9,273
Purchase of NCI of joint venture	—	—	—	(496)	—	—	(496)	(13)	(509)
Fair value of acquired noncontrolling interest	—	—	—	—	—	—	—	1,919	1,919
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(242)	(242)
Comprehensive Income:									
Net income	—	—	—	—	23,451	—	23,451	1,010	24,461
Other comprehensive income (loss)	—	—	—	—	—	(2,386)	(2,386)	(337)	(2,723)
Balances, December 31, 2014	122,046	$ 20,495	$ (170)	$ 666,769	$ (24,165)	$ (498)	$ 662,431	$ 3,783	$ 666,214

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Summary of Significant Accounting Policies

Nature of Operations — We are an international provider of contract drilling and drilling-related services and rental tools. We have operated in over 50 countries since beginning operations in 1934, making us among the most geographically experienced drilling contractors and rental tools providers in the world. We currently have operations in 23 countries. We own and operate drilling rigs and drilling-related equipment and also perform drilling-related services, referred to as operations and maintenance (O&M) services, for customer-owned drilling rigs on a contracted basis. We have extensive experience and expertise in drilling geologically difficult wells and in managing the logistical and technological challenges of operating in remote, harsh and ecologically sensitive areas. Our rental tools business supplies premium equipment to exploration and production (E&P) companies, drilling contractors and service companies on land and offshore in the United States (U.S.) and select international markets. We believe we are an industry leader in quality, health, safety and environmental practices.

Our business is currently comprised of five reportable segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, and Technical Services. Our rental tools business provides premium rental tools and services for land and offshore oil and natural gas drilling, workover and production applications. Tools we provide include drill collars, standard and heavy-weight drill pipe, all of which are available with standard or high-torque connections, tubing, and pressure control equipment including blow-out preventers (BOPs). In addition, we also provide services including fishing, tubular running, inspection and machine shop support. Our U.S. barge drilling business operates barge rigs that drill for oil and natural gas in shallow waters in and along the inland waterways and coasts of Louisiana, Alabama, and Texas. The majority of these wells are drilled in water depths of 6 to 12 feet. Our U.S. drilling business primarily consists of two arctic-class drilling rigs in Alaska designed to address the challenges presented by the remote location, harsh climate and sensitive environment that characterize the Alaskan North Slope and O&M work in support of a customer's offshore platform operations located in the Channel Islands region of California. Our international drilling business includes operations related to Parker-owned and customer-owned rigs. We provide O&M and other project management services, such as labor, maintenance, technical and logistics support for operators who own their own drilling rigs, but choose Parker Drilling to operate the rigs for them. Our technical services business includes engineering and related project services during concept development, pre-FEED (Front End Engineering Design) and FEED phases of customer-owned drilling facility projects. During the engineering, procurement, construction, installation and commissioning phases of these projects, we provide project management and procurement services focusing primarily on drilling equipment and drilling systems.

Consolidation — The consolidated financial statements include the accounts of the Company and subsidiaries in which we exercise control or have a controlling financial interest, including entities, if any, in which the Company is allocated a majority of the entity’s losses or returns, regardless of ownership percentage. If a subsidiary of Parker Drilling has a 50 percent interest in an entity but Parker Drilling’s interest in the subsidiary or the entity does not meet the consolidation criteria described above, then that interest is accounted for under the equity method.

Noncontrolling Interest — We apply accounting standards related to noncontrolling interests for ownership interests in our subsidiaries held by parties other than Parker Drilling. The entities that comprise the noncontrolling interest include ITS Arabia Limited and International Tubular Services - Egypt SAE. We report noncontrolling interest as equity on the consolidated balance sheets and report net income (loss) attributable to controlling interest and to noncontrolling interest separately on the consolidated statements of operations.

Reclassifications — Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications did not materially affect our consolidated financial results.

Revenue Recognition — Contract drilling revenues and expenses, comprised of daywork drilling contracts, call-outs against master service agreements and engineering and related project service contracts, are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment. Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized over the primary term of the related drilling contract; however, costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs. For contracts that are terminated prior to the specified term, early termination payments received by us are recognized as revenues when all contractual requirements are met. Revenues from rental activities are recognized ratably over the rental term which is generally less than six months. Technical Services contracts include engineering, consulting, and project management scopes of work and revenue is typically recognized on a time and materials basis.

Reimbursable Costs — The Company recognizes reimbursements received for out-of-pocket expenses incurred as revenues and accounts for out-of-pocket expenses as direct operating costs. Such amounts totaled \$82.6 million, \$69.7 million, and \$44.9 million during the years ended December 31, 2014, 2013, and 2012, respectively. Additionally, the Company typically receives a nominal handling fee, which is recognized as earned in revenues in our consolidated statement of operations.

Use of Estimates — The preparation of financial statements in accordance with accounting policies generally accepted in the United States (U.S. GAAP) requires us to make estimates and assumptions that affect our reported amounts of assets and liabilities, our disclosure of contingent assets and liabilities at the date of the financial statements, and our revenues and expenses during the periods reported. Estimates are typically used when accounting for certain significant items such as legal or contractual liability accruals, mobilization and deferred mobilization, self-insured medical/dental plans, income taxes and valuation allowance, and other items requiring the use of estimates. Estimates are based on a number of variables which may include third party valuations, historical experience, where applicable, and assumptions that we believe are reasonable under the circumstances. Due to the inherent uncertainty involved with estimates, actual results may differ from management estimates.

Purchase price allocation — We allocate the purchase price of an acquired business to its identifiable assets and liabilities based on estimated fair values at the transaction date in accordance with the acquisition method. Transaction and integration costs associated with an acquisition are expensed as incurred. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. We use all available information to estimate fair values, including quoted market prices, the carrying value of acquired assets, and widely accepted valuation techniques such as discounted cash flows. We typically engage third-party appraisal firms to assist in fair value determination of inventories, identifiable intangible assets, and any other significant assets or liabilities. Judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can materially impact our results of operations.

Intangible Assets – We recorded $8.5 million to recognize the fair value of definite-lived intangible assets assumed in the ITS Acquisition. Definite-lived intangible assets recorded in connection with the ITS Acquisition primarily relate to trade names, customer relationships, and developed technology and will be amortized over a weighted average period of approximately 3 years. See Note 2 - Acquisition of ITS for further discussion of the ITS Acquisition and fair value estimates.

Cash and Cash Equivalents — For purposes of the consolidated balance sheets and the consolidated statements of cash flows, the Company considers cash equivalents to be highly liquid debt instruments that have a remaining maturity of three months or less at the date of purchase.

Accounts Receivable and Allowance for Bad Debt — Trade accounts receivable are recorded at the invoice amount and typically do not bear interest. The allowance for bad debt is estimated for losses that may occur resulting from disputed amounts and the inability of our customers to pay amounts owed. We estimate the allowance based on historical write-off experience and information about specific customers. We review individually, for collectability, all balances over 90 days past due as well as balances due from any customer with respect to which we have information leading us to believe that a risk exists for potential collection.

Account balances are charged off against the allowance when we believe it is probable the receivable will not be recovered. We do not have any off-balance-sheet credit exposure related to customers.

The components of our accounts and notes receivable, net of allowance for bad debt balance are as follows:

	December 31,	
Dollars in thousands	**2014**	**2013**
Trade	$ 281,640	$ 270,498
Notes receivable	500	244
Allowance for bad debt[(1)]	(11,188)	(12,853)
Total accounts and notes receivable, net of allowance for bad debt	$ 270,952	$ 257,889

1) Additional information on the allowance for bad debt for the years ended December 31, 2014, 2013 and 2012 is reported on Schedule II — Valuation and Qualifying Accounts.

Property, Plant and Equipment — Property, plant and equipment is carried at cost. Maintenance and most repair costs are expensed as incurred. The cost of upgrades and replacements is capitalized. The Company capitalizes software developed or obtained for internal use. Accordingly, the cost of third-party software, as well as the cost of third-party and internal personnel that are directly involved in application development activities, are capitalized during the application development phase of new software systems projects. Costs during the preliminary project stage and post-implementation stage of new software systems projects, including data conversion and training costs, are expensed as incurred. We account for depreciation of property, plant and equipment on the straight line method over the estimated useful lives of the assets after provision for salvage value. Depreciation, for tax purposes, utilizes several methods of accelerated depreciation. Depreciable lives for different categories of property, plant and equipment are as follows:

Land drilling equipment	3 to 20 years
Barge drilling equipment	3 to 20 years
Drill pipe, rental tools and other	4 to 10 years
Buildings and improvements	5 to 30 years

Leasehold improvements are depreciated over the shorter of their estimated useful lives or the term of the lease.

Impairment — We review the carrying amounts of long-lived assets for potential impairment when events occur or circumstances change that indicate the carrying values of such assets may not be recoverable. We determine recoverability by evaluating the undiscounted estimated future net cash flows. When impairment is indicated, we measure the impairment as the amount by which the assets' carrying value exceeds its fair value. Management considers a number of factors such as estimated future cash flows from the assets, appraisals and current market value analysis in determining fair value. Assets are written down to fair value if the final estimate of current fair value is below the net carrying value.

Capitalized Interest — Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets. Capitalized interest costs reduce net interest expense in the consolidated statements of operations. During 2014, 2013 and 2012, capitalized interest costs were $1.2 million, $2.4 million and $10.2 million, respectively.

Assets held for sale — We classify an asset as held for sale when the facts and circumstances meet the criteria for such classification, including the following: (a) we have committed to a plan to sell the asset, (b) the asset is available for immediate sale, (c) we have initiated actions to complete the sale, including locating a buyer, (d) the sale is expected to be completed within one year, (e) the asset is being actively marketed at a price that is reasonable relative to its fair value, and (f) the plan to sell is unlikely to be subject to significant changes or termination.

Rig Materials and Supplies — Because our international drilling generally occurs in remote locations, making timely outside delivery of spare parts uncertain, a complement of parts and supplies is maintained either at the drilling site or in warehouses close to the operation. During periods of high rig utilization, these parts are generally consumed and replenished within a one-year period. During a period of lower rig utilization in a particular location, the parts, like the related idle rigs, are generally not transferred to other international locations until new contracts are obtained because of the significant transportation costs that would result from such transfers. We classify those parts which are not expected to be utilized in the following year as long-term assets. Additionally, our international rental tools business holds machine shop consumables and steel stock for manufacture in our machine shops and inspection and repair shops. Rig materials and supplies are valued at the lower of cost or market value.

Deferred Costs — We defer costs related to rig mobilization and amortize such costs over the primary term of the related contract. The costs to be amortized within twelve months are classified as current.

Debt Issuance Costs — We typically defer costs associated with issuance of indebtedness, and amortize those costs over the term of the related debt using the effective interest method.

Income Taxes — Income taxes are accounted for under the asset and liability method and have been provided based upon tax laws and rates in effect in the countries in which operations are conducted and income is earned. There is little or no expected relationship between the provision for or benefit from income taxes and income or loss before income taxes as the countries in which we operate have taxation regimes that vary not only with respect to nominal rate, but also in terms of the availability of deductions, credits, and other benefits. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which the temporary differences are expected to be recovered or settled and the effect of changes in tax rates is recognized in income in the period in which the change is enacted. The Company recognizes the effect of income tax positions only if those positions are more likely than not to be sustained. Recognized income tax positions are measured at the largest amount that is greater than 50 percent likely of being realized and changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

Earnings (Loss) Per Share (EPS) — Basic earnings (loss) per share is computed by dividing net income by the weighted average number of common shares outstanding during the period. The effects of dilutive securities, stock options, unvested restricted stock and convertible debt are included in the diluted EPS calculation, when applicable.

Concentrations of Credit Risk — Financial instruments that potentially subject the Company to concentrations of credit risk consist primarily of trade receivables with a variety of national and international oil and natural gas companies. We generally do not require collateral on our trade receivables.

At December 31, 2014 and 2013, we had deposits in domestic banks in excess of federally insured limits of approximately $59.3 million and $104.3 million, respectively. In addition, we had deposits in foreign banks, which were not insured at December 31, 2014 and 2013 of $54.4 million and $50.1 million, respectively.

Our customer base primarily consists of major, independent and national oil and natural gas companies and integrated service providers. We depend on a limited number of significant customers. Our largest customer, Exxon Neftegas Limited constituted 18.7 percent of our revenues for 2014.

Fair value measurements— For purposes of recording fair value adjustments for certain financial and non-financial assets and liabilities, and determining fair value disclosures, we estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation technique requires inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows: (1) unadjusted quoted prices for identical assets or liabilities in active markets (Level 1), (2) direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets (Level 2) and (3) unobservable inputs that require significant judgment for which there is little or no market data (Level 3). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Derivative Financial Instruments — We periodically use derivative instruments to manage risks associated with changes in associated interest rate fluctuations in connection with our 2015 Secured Credit Agreement (See Note 7 - Derivative Financial Instruments for further discussion). These derivative instruments, which consist of variable-to-fixed interest rate swaps, are not designated as hedges. Accordingly, the change in the fair value of the interest rate swaps is recognized in earnings at each reporting period.

Foreign Currency — In our international rental tool business, for certain subsidiaries and branches outside the U.S., the local currency is the functional currency. The financial statements of these subsidiaries and branches are translated into U.S. dollars as follows: (i) assets and liabilities at month-end exchange rates; (ii) income, expenses and cash flows at monthly average exchange rates or exchange rates in effect on the date of the transaction; and (iii) stockholders' equity at historical exchange rates. For those subsidiaries where the local currency is the functional currency, the resulting translation adjustment is recorded as a component of accumulated other elements of comprehensive income (loss) in the accompanying consolidated balance sheets.

Stock-Based Compensation — Under our long term incentive plan, we are authorized to issue the following: stock options; stock appreciation rights; restricted stock awards; restricted stock units; performance based awards; and other types of awards in cash or stock to key employees, consultants, and directors. We typically grant restricted stock units (RSUs), performance shares units (PSUs) and performance cash units (PCUs). Our RSUs are service-based awards and compensation expense is recognized ratably over the applicable vesting period, which is typically three years for employees. RSUs granted to non-management directors typically vest at the end of a one-year vesting period. The grant-date fair value of nonvested RSUs is determined based on the closing trading price of the company's shares on the grant date. Our RSUs are settled in stock upon vesting.

Our PSU and PCU awards contain payout conditions which are based on our performance against our peers with regard to relative total shareholder return (TSR) and absolute and relative return on capital employed (ROCE). The effects of these conditions are reflected in the grant-date fair value of the award using a lattice model for valuation. Typically, PSUs are settled in stock upon vesting and PCUs are settled in cash upon vesting. Both PSUs and PCUs vest fully at the end of a three year performance period. We evaluate the terms of each PSU and PCU award to determine if the award should be accounted for as equity or a liability under the stock compensation rules of U.S. GAAP. Compensation costs for PSUs and PCUs are recognized ratably over the service period.

Share-based compensation expense is recognized, net of an estimated forfeiture rate, which is based on historical experience and adjusted, if necessary, in subsequent periods based on actual forfeitures. We recognize share-based compensation expense in the same financial statement line item as cash compensation paid to the respective employees. Tax deduction benefits for awards in excess of recognized compensation costs are reported as a financing cash flow.

Legal and Investigation Matters — As of December 31, 2014, we have accrued an estimate of the probable and estimable costs for the resolution of certain legal and investigation matters. We have not accrued any amounts for other matters for which the liability is not probable and reasonably estimable. Generally, the estimate of probable costs related to these matters is developed in consultation with our legal advisors. The estimates take into consideration factors such as the complexity of the issues, litigation risks and settlement costs. If the actual settlement costs, final judgments, or fines, after appeals, differ from our estimates, our future financial results may be adversely affected.

Note 2 — Acquisition of ITS

On April 22, 2013 we acquired International Tubular Services Limited (ITS) and related assets (the ITS Acquisition) for an initial purchase price of $101 million paid at the closing of the ITS Acquisition. An additional $24 million was deposited into an escrow account, which is payable to the seller or to us, as the case may be, in accordance with the ITS Acquisition agreement (the Acquisition Agreement). As of December 31, 2014, $10.5 million of the cash deposited in escrow has been released to the seller. Additionally, during the year ended December 31, 2014, we received $2.75 million from the escrow to reimburse the Company for certain post-acquisition expenditures. The reimbursements were recorded as a reduction to general and administrative expense on our consolidated statement of operations.

Fair value of Consideration Transferred

The following details the fair value of the consideration transferred to effect the ITS Acquisition (dollars in thousands):

Dollars in thousands		
Cash paid to, or on behalf of, ITS and its equity holders	$	101,000
Cash deposited in escrow		19,000
Fair value of contingent consideration deposited in escrow for assets not acquired (1)		5,000
Total fair value of the consideration transferred	$	125,000

(1) Based on the terms of the Acquisition Agreement, $5 million of the $24 million in escrow to be paid to the seller was contingent upon certain future liabilities that could become due by ITS in certain jurisdictions. Any payments in relation to these liabilities would be deducted from the $5 million escrow amount and the net balance of the escrow would be paid to the seller. During the year ended December 31, 2014, the escrow agent released $2 million to the seller, leaving $3 million remaining in escrow at December 31, 2014. We anticipate the balance of $3 million will be paid to the seller. Based on the payments and recoveries out of escrow, the estimated fair value of the consideration in escrow related to these liabilities is $3 million. Any changes to the fair value of the contingent consideration in the future of less than $3 million will result in recording a receivable from escrow which will be recorded at fair value. We do not expect to recover any further amounts from escrow related to the contingent consideration; therefore, as of December 31, 2014, the fair value of the receivable was zero.

Allocation of Consideration Transferred to Net Assets Acquired

We have finalized the determination of the fair values of the assets acquired and liabilities assumed as set forth below. The acquired assets and assumed liabilities were subject to adjustment during a one-year measurement period subsequent to the ITS Acquisition as permitted under GAAP. The estimated fair values of certain assets and liabilities, primarily receivables, intangible assets, property, plant and equipment, taxes, contingencies and noncontrolling interests required judgments and assumptions that resulted in adjustments made to these estimates during the measurement period. The measurement period adjustments were recorded to reflect new information obtained about facts and circumstances existing as of the date of the ITS Acquisition and did not result from subsequent intervening events.

The following details the allocation of consideration transferred to net assets acquired in the ITS Acquisition:

Dollars in thousands	**April 22, 2013**
Cash and cash equivalents	$ 7,009
Accounts and notes receivable, net (1)	48,184
Other current assets	1,803
Accounts payable and accrued liabilities	(35,156)
Accrued income taxes	(1,251)
Working capital excluding rig materials and supplies	20,589
Rig materials and supplies	11,514
Property, plant and equipment, net (2)	72,935
Investment in joint venture	4,134
Other noncurrent assets	2,818
Total tangible assets	111,990
Deferred income tax assets - current	222
Deferred income tax assets - noncurrent (3)	11,640
Intangible assets (4)	8,500
Total assets acquired	132,352
Other long-term liabilities	(211)
Long-term deferred tax liability	(2,796)
Net assets acquired	129,345
Less: Noncontrolling interest (5)	(4,345)
Total consideration transferred	$ 125,000

1) Our provisional allocation included $54.7 million of gross contractual accounts receivable. During the 2013 fourth quarter, adjustments of $1.2 million were recorded as of December 31, 2013 resulting in final fair value of gross accounts receivable of $55.9 million. These adjustments were recorded to reflect recognition of receivables for revenue earned prior to the acquisition date. Additionally, the initial allocation included $5.9 million of allowance for doubtful accounts. During the 2014 first quarter, we recorded an additional $1.9 million allowance to reserve against receivables that existed as of the acquisition date and were deemed to be uncollectible based on information obtained during the measurement period that existed, but was unknown to us, at the time of acquisition.

2) Our provisional allocation included $39.2 million of accounts payable and accrued liabilities. During the 2013 third quarter we recorded a reclassification of $4.0 million to reclassify reserves to property, plant, and equipment. This reclassification was reflected in our December 31, 2013 consolidated balance sheet but was not included in our disclosure of the Allocation of Consideration Transferred to Net Assets Acquired as of December 31, 2013. We have corrected this as of March 31, 2014 and do not believe the reclassification is material to our previously reported disclosure.

3) Management determined that the fair value of the net assets acquired less noncontrolling interest equaled consideration paid; therefore, no goodwill was recorded. Our provisional allocation included an adjustment of $40.2 million to reduce the historical carrying value of the acquired property, plant and equipment to its estimated fair value at the date of acquisition. The measurement period adjustments to receivables, deferred income taxes, intangibles, and noncontrolling interests directly impacted the determination of the final fair value of the acquired property, plant and equipment, resulting in measurement period adjustments totaling $2.6 million to increase the fair value of property, plant and equipment.

4) Our provisional allocation included $14.4 million of deferred tax assets. During the measurement period, adjustments of ($2.9) million and $0.4 million were recorded as of December 31, 2013 and March 31, 2014, respectively, resulting in final fair value of deferred tax assets of $11.9 million. Adjustments to deferred income tax assets primarily related to the differences between the final acquisition date fair value and tax basis of acquired property, plant and equipment.

5) Our provisional allocation included $10.0 million and $0.2 million to reflect the estimated fair values of definite- and indefinite-lived intangible assets, respectively. During the 2013 fourth quarter we recorded adjustments of $1.5 million and $0.2 million to reduce the value of the definite- and indefinite-lived intangible assets down to $8.5 million and zero respectively. Our depreciation and amortization expense for the year ended December 31, 2013 reflects this valuation adjustment. Definite-lived intangible assets recorded in connection with the ITS Acquisition, which primarily relate to trade names, customer relationships, and developed technology, are being amortized over a weighted average period of approximately 3.4 years.

6) Our provisional allocation included noncontrolling interest of $2.7 million. The estimated fair value of the noncontrolling interest was calculated as a percentage of the net assets acquired related to certain subsidiaries in which ITS holds less than a 100 percent controlling interest. The fair value of the net assets of these subsidiaries was primarily based on the income approach valuation model. During the 2014 first quarter, we obtained information about the acquired subsidiaries that existed at the date of acquisition which resulted in an increase in the acquisition date fair value of $1.6 million, resulting in a final fair value of the noncontrolling interest of $4.3 million.

The impacts to our December 31, 2013 consolidated balance sheet for the revisions to the provisional allocation made during the 2014 first quarter are as follows:

Dollars in thousands	Increase/(Decrease)
Accounts and notes receivable, net	$ (1,859)
Total current assets	(1,859)
Property, plant and equipment	3,072
Deferred income tax assets - noncurrent	391
Total non-current assets	3,463
Total assets	$ 1,604
Long-term deferred tax liabilities	(60)
Total non-current liabilities	(60)
Total liabilities	$ (60)
Noncontrolling interest	$ 1,664
Total liabilities and stockholder's equity	$ 1,604

The impact of the revisions to the provisional allocation recorded during the 2014 first quarter, including the impact to depreciation expense related to the increase in property, plant and equipment, are not material to our historical consolidated financial statements or disclosures.

Acquisition-Related Costs

Acquisition-related transaction costs, consisting of various advisory, compliance, legal, accounting, valuation and other professional or consulting fees, were nominal for the year ended December 31, 2014 and were $22.5 million for the year ended December 31, 2013. These costs were expensed as incurred and included in general and administrative expense on our consolidated condensed statement of operations. Debt issuance costs of $5.4 million associated with our $125.0 million term loan, fully funded by Goldman Sachs Bank USA as Sole Lead Arranger and Administrative Agent (the Goldman Term Loan) issued on April 18, 2013 were initially deferred to be amortized to interest expense over the life of the term loan. However, the Goldman Term Loan was repaid on July 30, 2013 with net proceeds from the issuance of $225.0 million aggregate principal amount of 7.50% Senior Notes due August 1, 2020 (the 7.50% Notes), and the unamortized deferred costs of $5.2 million were expensed during the third quarter of 2013.

Note 3 — Accumulated Other Comprehensive Income

Accumulated other comprehensive income consisted of the following:

Dollars in thousands	Foreign Currency Items	
December 31, 2013	$	1,888
Current period other comprehensive income		(2,386)
December 31, 2014	$	(498)

Amounts reclassified out of accumulated other comprehensive income were $0.2 million for the year ended December 31, 2014. These amounts represent foreign currency translation losses from the sale of our equity method investment in an ITS entity acquired during 2013. The other comprehensive income for the current period includes a significant increase in the exchange rate on related borrowings primarily in Colombia.

Note 4 — Property, Plant and Equipment

The components of our property, plant and equipment balance are as follows:

	December 31,			
Dollars in Thousands	2014		2013	
Property, Plant and Equipment, at cost:				
Drilling Equipment	$	1,383,308	$	1,346,477
Rental Tools		494,924		467,731
Building, Land and Improvements		53,024		49,518
Other		95,074		61,273
Construction in Progress		70,668		82,381
Total Property, Plant and Equipment at cost		2,096,998		2,007,380
Less: Accumulated Depreciation and Amortization		1,201,058		1,136,024
Property, Plant, and Equipment, Net	$	895,940	$	871,356

Depreciation expense was $145.1 million, $134.1 million and $113.0 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Provision for Reduction in Carrying Value of an Asset

During the 2014 fourth quarter, we performed a recoverability test for our respective asset groups to determine if the carrying values of such assets are recoverable. Based on the results of our recoverability test, the current carrying values of our asset groups are fully recoverable through our future estimated cash flows. We therefore concluded that the asset groups were not subject to impairment at December 31, 2014.

During the 2013 fourth quarter, for two rigs previously reported as assets held for sale as of December 31, 2012, management concluded that facts and circumstances no longer support the expectation that a sale would be consummated within a reasonable time period. As a result, we reclassified these assets back to assets held and used in accordance with generally accepted accounting principles. Concurrently, we performed a recoverability test for the two rigs and determined the fair value was less than the carrying amount before the assets were classified as held for sale, adjusted for any depreciation expense that would have been recognized had the assets been continuously classified as held and used. Therefore, during the 2013 fourth quarter we recorded a non-cash charge of $1.9 million to reflect the rigs current estimated fair value. Additionally, during the 2013 fourth quarter a sales agreement was terminated for three additional rigs which were previously expected to be sold prior to December 31, 2013. Upon termination of the sales agreement we performed a fair value analysis of the rigs and concluded for one rig, the carrying value of the rig exceeded fair value. Therefore, during the 2013 fourth quarter we recorded a non-cash charge of $0.6 million. Fair value was based on expected future cash flows using Level 3 inputs in accordance with fair value measurement requirements. The two rigs are reported as part of the International Drilling segment.

Disposition of Assets

During the normal course of operations, we periodically sell equipment deemed to be excess, obsolete, or not currently required for operations. During the 2014 fourth quarter, we sold two rigs located in Kazakhstan, including rig related inventory, property and leasehold improvements. The assets had a carrying value at the time of sale of $3.8 million and were sold for proceeds of $3.5 million, resulting in a net loss of approximately $0.3 million.

During the 2013 fourth quarter, we sold two rigs located in New Zealand, including rig related inventory, property and leasehold improvements. The assets had a carrying value at the time of sale of $2.3 million and were sold for proceeds of $3.2 million resulting in a gain of approximately $0.9 million. The assets were part of our international drilling rig fleet. During the 2013 fourth quarter we also completed the sale of a building located in Tulsa, Oklahoma. As a result of the completed sale, we recognized proceeds of $0.8 million and $0.1 million gain on the sale. Additionally, during the 2013 third quarter we sold a barge rig located in Mexico with carrying value at the time of sale of $0.3 million for proceeds of $0.5 million, resulting in a $0.2 million gain. The barge rig was part of our Latin America rig fleet and has historically been included in the international drilling segment.

During the 2012 fourth quarter, we sold a 33 year-old posted barge drilling rig for proceeds of $0.2 million, resulting in a $0.5 million loss.

Assets Held for Sale

We had no assets classified as assets held for sale as of December 31, 2014 or as of December 31, 2013. During 2013, for five rigs previously reported as assets held for sale, management concluded that facts and circumstances no longer supported the expectation that a sale would be consummated within a reasonable time period. During the 2013 second quarter, we reclassified three rigs from assets held for sale to assets held and used and inventory. We initially classified the three rigs as assets held for sale as of December 31, 2010. We performed an analysis of the fair value of the three rigs and determined the rigs' carrying amount was less than fair value; therefore, the rigs were reclassified at their carrying amount at the time the assets were classified as held for sale, adjusted for depreciation expense that would have been recognized had the assets been continuously classified as held and used. The amount of additional depreciation recorded during the 2013 second quarter to place the assets in held and used categorization was $0.7 million.

Additionally, during the 2013 fourth quarter we reclassified two rigs from assets held for sale to assets held and used and inventory. We initially classified these rigs as held for sale as of September 30, 2012. We performed an analysis of the fair value of the two rigs and determined the fair value was less than the carrying amount before the assets were classified as held for sale, adjusted for any depreciation expense that would have been recognized had the assets been continuously classified as held and used. Therefore, during the 2013 fourth quarter we recorded a non-cash charge of $1.9 million to reflect the rigs current estimated fair value. During 2013, we adjusted the Assets held for sale, Inventory, and Property, plant and equipment balances for the year ended December 31, 2012 from what was reported in our December 31, 2012 Form 10-K, to reflect the reclassification of these assets.

Note 5 — Income Taxes

Income before income taxes is summarized below:

	Year Ended December 31,		
Dollars in thousands	2014	2013	2012
United States	$ 37,547	$ 32,136	$ 52,422
Foreign	10,990	20,651	18,555
	$ 48,537	$ 52,787	$ 70,977

Income tax expense (benefit) is summarized as follows:

Dollars in thousands	Year Ended December 31, 2014	2013	2012
Current:			
United States:			
Federal	$ (3,079)	$ (3,658)	$ 7,791
State	5,335	1,968	733
Foreign	20,311	14,599	9,518
Deferred:			
United States:			
Federal	4,703	10,720	15,612
State	(379)	2,820	4,296
Foreign	(2,815)	(841)	(4,071)
	$ 24,076	$ 25,608	$ 33,879

Total income tax expense differs from the amount computed by multiplying income before income taxes by the U.S. federal income tax statutory rate. The reasons for this difference are as follows:

	Year Ended December 31,					
	2014		2013		2012	
Dollars in thousands	Amount	% of Pre-Tax Income	Amount	% of Pre-Tax Income	Amount	% of Pre-Tax Income
Computed Expected Tax Expense	$ 16,988	35.0 %	$ 18,476	35.0 %	$ 24,842	35.0 %
Foreign Taxes	11,221	23.1 %	12,470	23.6 %	13,171	18.6 %
Tax Effect Different From Statutory Rates	(3,389)	(7.0)%	(8,920)	(16.9)%	(8,080)	(11.4)%
State Taxes, net of federal benefit	3,117	6.4 %	4,099	7.8 %	4,757	6.7 %
Foreign Tax Credits	(3,043)	(6.3)%	(1,484)	(2.8)%	(1,867)	(2.6)%
Change in Valuation Allowance	2,800	5.8 %	1,975	3.7 %	(1,662)	(2.3)%
Uncertain Tax Positions	(1,125)	(2.3)%	2,472	4.7 %	(6,642)	(9.4)%
Permanent Differences	676	1.4 %	4,005	7.6 %	5,477	7.7 %
Prior Year Return to Provision Adjustments	(2,618)	(5.4)%	(6,268)	(11.9)%	4,057	5.7 %
Other	(551)	(1.1)%	(1,217)	(2.3)%	(174)	(0.2)%
Unremitted Foreign Earnings-Current Year Adjustment	—	— %	—	— %	—	— %
Actual Tax Expense	$ 24,076	49.6 %	$ 25,608	48.5 %	$ 33,879	47.8 %

The components of the Company's deferred tax assets and liabilities as of December 31, 2014 and 2013 are shown below:

	December 31,	
Dollars in thousands	2014	2013
Deferred tax assets		
Current deferred tax assets:		
Reserves established against realization of certain assets	$ 2,156	$ 1,504
Accruals not currently deductible for tax purposes	4,897	7,223
Other state deferred tax asset, net	412	990
Foreign Local Office	11	223
Gross current deferred tax assets	7,476	9,940
Current deferred tax valuation allowance	—	—
Net current deferred tax assets	7,476	9,940
Non-current deferred tax assets:		
Federal net operating loss carryforwards	17,235	—
State net operating loss carryforwards	1,130	864
Other state deferred tax asset, net	1,246	1,909
Foreign Tax Credits	37,344	27,462
FIN 48	4,870	8,317
Foreign tax	28,645	18,499
Asset Impairment	38,931	48,743
Accruals not currently deductible for tax purposes	—	1,017
Deferred compensation	3,210	2,436
Other	—	—
Gross long-term deferred tax assets	132,611	109,247
Valuation Allowance	(9,922)	(6,827)
Net non-current deferred tax assets, net of valuation allowance	122,689	102,420
Net deferred tax assets	130,165	112,360
Deferred tax liabilities:		
Non-current deferred tax liabilities:		
Property, Plant and equipment	(43,637)	(32,505)
Foreign tax local	(4,985)	(1,440)
Other state deferred tax liability, net	(3,491)	(4,819)
Other	(2)	(3)
Gross non-current deferred tax liabilities	(52,115)	(38,767)
Net deferred tax asset	$ 78,050	$ 73,593

As part of the process of preparing the consolidated financial statements, the Company is required to determine its provision for income taxes. This process involves estimating the annual effective tax rate and the nature and measurements of temporary and permanent differences resulting from differing treatment of items for tax and accounting purposes. These differences and the operating loss and tax credit carryforwards result in deferred tax assets and liabilities. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income of appropriate character in each taxing jurisdiction during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax planning strategies in making this assessment. To the extent the Company believes that it does not meet the test that recovery is more likely than not, it establishes a valuation allowance. To the extent that the Company establishes a valuation allowance or changes this allowance in a period, it adjusts the tax provision or tax benefit in the consolidated statement of operations. We use our judgment in determining provisions or benefits for income taxes, and any valuation allowance recorded against previously established deferred tax assets. Based upon the factors considered by management in assessing the realizability of the deferred tax assets, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31,

2014. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

On September 13, 2013, the U.S. Treasury Department and the Internal Revenue Service issued final regulations that address costs incurred in acquiring, producing, or improving tangible property (the "tangible property regulations"). The tangible property regulations are generally effective for tax years beginning on or after January 1, 2014. The tangible property regulations required the Company to make additional tax accounting method changes as of January 1, 2014; however, the impact of these changes has not been material to the Company's consolidated financial position, its results of operations, or both.

The 2014 results include income tax benefits of $2.2 million related to the settlement of our US Federal Internal Revenue Service refund claim for periods 2008-2011 and $25.0 million for depreciation and amortization relating to our two arctic-class drilling rigs in Alaska. In addition, we increased our valuation allowance by $2.8 million primarily related to foreign net operating losses.

The 2013 results include income tax benefits of $3.3 million related to the enacted Mexican tax reform as applied to the expected future utilization of deferred tax assets and liabilities and $20.9 million for depreciation and amortization relating to our two arctic-class drilling rigs in Alaska. In addition, we increased our valuation allowance by $2.0 million primarily related to foreign net operating losses.

The 2012 results include income tax expenses of $1.7 million related to the effective settlement of our US Federal Internal Revenue Service examination for the 2006 through 2010 periods and $7.7 million for depreciation and amortization relating to our two arctic-class drilling rigs in Alaska. In addition, we decreased our valuation allowance by $1.7 million primarily related to foreign NOLs.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

Dollars in thousands		
Balance at January 1, 2014	$	(12,209)
Additions based on tax positions taken during a prior period		(3,862)
Additions based on tax positions taken during the current period		(385)
Reductions related to settlement of tax matters		6,088
Reductions based on tax positions taken during a prior period		2,169
Balance at December 31, 2014	$	(8,199)

In many cases, our uncertain tax positions are related to tax years that remain subject to examination by tax authorities. The following describes the open tax years, by major tax jurisdiction, as of December 31, 2014:

Colombia	2010-present
Kazakhstan	2007-present
Mexico	2009-present
Papua New Guinea	2011-present
Russia	2011-present
United States — Federal	2012-present
United Kingdom	2012-present

At December 31, 2014, we had a liability for unrecognized tax benefits of $8.2 million ($3.6 million of which, if recognized, would favorably impact our effective tax rate), which includes payments of approximately $6.1 million made during 2014 in settlement of notices of assessment in Kazakhstan which were fully reserved.

The Company recognized interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2014 and December 31, 2013 we had approximately $3.3 million and $7.9 million of accrued interest and penalties related to uncertain tax positions, respectively. We recognized an increase of $0.7 million of interest and no penalties on unrecognized tax benefits for the year ended December 31, 2014.

As of December 31, 2014, the Company has permanently reinvested accumulated undistributed earnings of foreign subsidiaries and, therefore, has not recorded a deferred tax liability related to subject earnings. Upon distribution of additional earnings in the form of dividends or otherwise, we would likely be subject to US income taxes and foreign withholding taxes. It is not practicable to determine precisely the amount of taxes that may be payable on the eventual remittance of these earnings because of the application of US foreign tax credits. While we currently claim foreign tax credits, we may not be in a credit position if and when future remittances of foreign earnings occur, or the limitation imposed by the Internal Revenue Code and regulations thereunder may not allow the credits to be utilized during the applicable carryback and carryforward periods.

Note 6 — Long-Term Debt

The following table illustrates the Company's current debt portfolio as of December 31, 2014 and December 31, 2013:

	December 31,	
Dollars in thousands	2014	2013
6.75% Senior Notes, due July 2022	$ 360,000	$ —
7.50% Senior Notes, due August 2020	225,000	225,000
9.125% Senior Notes, due April 2018	—	428,781
Term Note, due December 2017	30,000	—
Total debt	615,000	653,781
Less current portion (1)	10,000	25,000
Total long-term debt	$ 605,000	$ 628,781

(1) Current portion of the Term Loan

Subsequent to year end we increased our liquidity by entering into the Second Amended and Restated Credit Agreement (the 2015 Secured Credit Agreement) on January 26, 2015. This agreement amends and restates the Amended and Restated Credit Agreement (the 2012 Secured Credit Agreement) dated December 14, 2012. The 2015 Secured Credit Agreement is comprised of a $200.0 million revolving credit facility (2015 Revolver). The 2012 Secured Credit Agreement consisted of an $80.0 million revolving credit facility and a $50 million senior secured term loan facility (Term Loan). At the closing of the 2015 Secured Credit Agreement we repaid $30.0 million of Term Loan borrowings under the 2012 Secured Credit Agreement with a $30.0 million draw under the 2015 Revolver. There were no borrowings under the revolver portion of the 2012 Secured Credit Agreement.

6.75% Senior Notes, due July 2022

On January 22, 2014, we issued $360.0 million aggregate principal amount of the 6.75% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 6.75% Notes offering plus a $40.0 million Term Loan draw under the 2012 Secured Credit Agreement and cash on hand were utilized to purchase $416.2 million aggregate principal amount of our outstanding 9.125% Senior Notes due 2018 pursuant to a tender and consent solicitation offer commenced on January 7, 2014. See further discussion of the tender and consent solicitation offer below entitled "*9.125% Senior Notes, due April 2018*".

The 6.75% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 6.75% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the 2015 Secured Credit Agreement and our 7.50% Notes. Interest on the 6.75% Notes is payable on January 15 and July 15 of each year, beginning July 15, 2014. Debt issuance costs related to the 6.75% Notes of approximately $7.6 million ($7.0 million net of amortization as of December 31, 2014) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to January 15, 2017, we may redeem up to 35 percent of the aggregate principal amount of the 6.75% Notes at a redemption price of 106.75 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after January 15, 2018, we may redeem all or a part of the 6.75% Notes upon appropriate notice, at a redemption price of 103.375 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning January 15, 2020. If we experience certain changes in control, we must offer to repurchase the 6.75% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as events of default. These covenants are subject to a number of important exceptions and qualifications.

7.50% Senior Notes, due August 2020

On July 30, 2013, we issued $225.0 million aggregate principal amount of the 7.50% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 7.50% Notes offering were primarily used to repay the $125.0 million aggregate principal amount of the Goldman Term Loan, to repay $45.0 million of Term Loan borrowings and for general corporate purposes.

The 7.50% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 7.50% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the 2015 Secured Credit Agreement and the 6.75% Notes. Interest on the 7.50% Notes is payable on February 1 and August 1 of each year, beginning February 1, 2014. Debt issuance costs related to the 7.50% Notes of approximately $5.6 million ($4.7 million, net of amortization as of December 31, 2014) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to August 1, 2016, we may redeem up to 35 percent of the aggregate principal amount of the 7.50% Notes at a redemption price of 107.50 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after August 1, 2016, we may redeem all or a part of the 7.50% Notes upon appropriate notice, at a redemption price of 103.750 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning August 1, 2018. If we experience certain changes in control, we must offer to repurchase the 7.50% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as events of default. These covenants are subject to a number of important exceptions and qualifications.

9.125% Senior Notes, due April 2018

On March 22, 2010, we issued $300.0 million aggregate principal amount of the 9.125% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 9.125% Notes offering were primarily used to redeem the $225.0 million aggregate principal amount of our 9.625% Senior Notes due 2013 and to repay $42.0 million of borrowings under our senior secured revolving credit facility.

On April 25, 2012, we issued an additional $125.0 million aggregate principal amount of 9.125% Notes under the same indenture at a price of 104.0 percent of par, resulting in gross proceeds of $130.0 million. Net proceeds from the offering were utilized to refinance $125.0 million aggregate principal amount of the 2.125% Convertible Senior Notes due July 2012.

On January 7, 2014, we commenced a tender and consent solicitation with respect to the 9.125% Notes. The tender offer price was $1,061.98, inclusive of a $30.00 consent payment, for each $1,000 principal amount of 9.125% Notes, plus accrued and unpaid interest. On January 22, 2014, we paid $453.7 million for the tendered 9.125% Notes, comprised of $416.2 million of aggregate principal amount of the 9.125% Notes, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. On April 1, 2014, we redeemed the remaining $8.8 million aggregate principal amount of the outstanding 9.125% Notes for a purchase price of $9.6 million, inclusive of a $0.4 million call premium and $0.4 million interest. During the year ended December 31, 2014, we recorded a loss on extinguishment of debt of approximately $30.2 million, which included the tender and consent premiums of $25.8 million, the call premium of $0.4 million and the write-off of unamortized debt issuance costs of $7.7 million, offset by the write-off of the remaining unamortized debt issuance premium of $3.8 million.

2015 Secured Credit Agreement

On January 26, 2015 we entered into the 2015 Secured Credit Agreement, which amended and restated the 2012 Secured Credit Agreement. The 2015 Secured Credit Agreement is comprised of a $200.0 million revolving credit facility (2015 Revolver). The 2012 Secured Credit Agreement consisted of an $80.0 million revolving credit facility and a $50.0 million Term Loan. At the closing of the 2015 Secured Credit Agreement, we repaid $30.0 million of Term Loan borrowings under the 2012 Secured Credit Agreement with a $30.0 million draw under the 2015 Revolver. At the closing date there were no borrowings under the revolving credit portion of the 2012 Secured Credit Agreement.

Our 2015 Revolver is available for general corporate purposes and to support letters of credit. Interest on 2015 Revolver loans accrues at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. Under the 2015 Secured Credit Agreement, the Applicable Rate varies from a rate per annum ranging from 2.50 percent to 3.00 percent for LIBOR rate loans and 1.50 percent to 2.00 percent for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the 2015 Secured

Credit Agreement). Revolving loans are available subject to a quarterly Asset Coverage Ratio calculation based on the Orderly Liquidation Value of certain specified rigs including barge rigs in the Gulf of Mexico and land rigs in Alaska, and rental equipment of the Company and its subsidiary guarantors and a percentage of eligible domestic accounts receivable. Upon closing of the 2015 Secured Credit Agreement, there was $30.0 million drawn on the 2015 Revolver and $11.7 million of letters of credit outstanding. The 2015 Secured Credit Agreement matures on January 26, 2020.

2012 Secured Credit Agreement

On December 14, 2012, we entered into the 2012 Secured Credit Agreement consisting of a senior secured $80.0 million revolving facility (2012 Revolver) and a senior secured term loan facility (Term Loan). In July 2013, the 2012 Secured Credit Agreement was amended to permit re-borrowing in the form of additional term loans, of up to $45.0 million, decreasing by $2.5 million at the end of each quarter beginning September 30, 2013 and ending March 31, 2014. In January 2014 we re-borrowed $40 million of the Term Loan.

Our obligations under the 2012 Secured Credit Agreement were guaranteed by substantially all of our direct and indirect domestic subsidiaries other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States, each of which had executed guaranty agreements, and were secured by first priority liens on our accounts receivable, specified barge rigs and rental equipment. The 2012 Secured Credit Agreement contained customary affirmative and negative covenants with which we were in compliance as of December 31, 2014 and December 31, 2013. The 2012 Secured Credit Agreement would have matured on December 14, 2017.

2012 Revolver

Our 2012 Revolver was available for general corporate purposes and to support letters of credit. Interest on 2012 Revolver loans accrued at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. Under the 2012 Secured Credit Agreement, the Applicable Rate varied from a rate per annum ranging from 2.50 percent to 3.00 percent for LIBOR rate loans and 1.50 percent to 2.00 percent for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the 2012 Secured Credit Agreement). Revolving loans were available subject to an asset coverage ratio determined based on a percentage of eligible accounts receivable, certain specified barge drilling rigs and rental equipment of the Company and its subsidiary guarantors. There were no revolving loans outstanding at December 31, 2014 and December 31, 2013. Letters of credit outstanding as of December 31, 2014 and December 31, 2013 totaled $11.0 million and $4.6 million, respectively.

Term Loan

The Term Loan originated at $50.0 million on December 14, 2012 and required quarterly principal payments of $2.5 million, which began March 31, 2013. Interest on the Term Loan accrued at a Base Rate plus 2.00 percent or LIBOR plus 3.00 percent. The outstanding balance on the Term Loan at December 31, 2013 was zero. In January 2014 we re-borrowed $40.0 million of the Term Loan and used the proceeds, along with the proceeds from the issuance of the 6.75% Notes, to repurchase our 9.125% Notes. As of December 31, 2014 the remaining balance on the Term Loan was $30.0 million. At the closing of the 2015 Secured Credit Agreement, we repaid $30.0 million of Term Loan borrowings under the 2012 Secured Credit Agreement with a $30.0 million draw under the 2015 Revolver.

Note 7 — Derivative Financial Instruments

During the year ended December 31, 2011, we entered into two variable-to-fixed interest rate swap agreements as a strategy to manage the floating rate risk on the Term Loan borrowings under the then-effective secured credit agreement. The two agreements fixed the interest rate on a notional amount of $73.0 million of borrowings at 3.878 percent for the period beginning June 27, 2011 and terminating May 14, 2013. The notional amount of the swap agreements decreased correspondingly with amortization of the Term Loan under the then-effective secured credit agreement. We did not apply hedge accounting to the agreements and, accordingly, change in the fair value of the interest rate swaps were recognized in earnings. As of December 31, 2013 the swap agreements had expired and as of December 31, 2012, the fair value of the interest rate swap was a liability of $0.1 million and was recorded in accrued liabilities in our consolidated balance sheets. For both years ended December 31, 2013 and December 31, 2012, we recognized in earnings a nominal gain relating to these contracts.

During the years ended December 31, 2013 and 2014, we did not enter into any new swap agreements, nor was there any impact to our consolidated balance sheets or our consolidated statement of operations.

Note 8 — Fair Value of Financial Instruments

Certain of our assets and liabilities are required to be measured at fair value on a recurring basis. For purposes of recording fair value adjustments for certain financial and non-financial assets and liabilities, and determining fair value disclosures, we estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability.

The FASB fair value measurement and disclosure guidance requires inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows:

- Level 1 — Unadjusted quoted prices for identical assets or liabilities in active markets;
- Level 2 — Direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities inactive markets or identical assets or liabilities in less active markets;
- Level 3 — Unobservable inputs that require significant judgment for which there is little or no market data.

When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable. The amounts reported in our consolidated balance sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The carrying amount of our interest rate swap agreements represents the estimated fair value, measured using Level 2 inputs. As of December 31, 2013 the swap agreements had expired.

Fair value of our debt instruments is determined using Level 2 inputs. Fair values and related carrying values of our debt instruments are as follows:

	December 31, 2014		December 31, 2013	
Dollars in thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term Debt				
6.75% Notes	$ 360,000	$ 270,000	$ —	$ —
7.50% Notes	225,000	180,000	225,000	236,250
9.125% Notes	—	—	425,000	446,250
Total	$ 585,000	$ 450,000	$ 650,000	$ 682,500

The assets acquired and liabilities assumed in the ITS Acquisition were recorded at fair value in accordance with U.S. GAAP. Acquisition date fair values represent either Level 2 fair value measurements (current assets and liabilities, property, plant and equipment) or Level 3 fair value measurements (intangible assets).

Market conditions could cause an instrument to be reclassified from Level 1 to Level 2, or Level 2 to Level 3. There were no transfers between levels of the fair value hierarchy or any changes in the valuation techniques used during the year ended December 31, 2014.

Note 9 — Stock-Based Compensation

Stock Plan

In 2014 and 2013 stock-based compensation awards were granted to employees under the Company's 2010 Long-Term Incentive Plan, as amended and restated in May 2013 (the Stock Plan).

The Stock Plan was approved by the stockholders at the Annual Meeting of Stockholders on May 8, 2013. The Stock Plan authorizes the compensation committee or the board of directors to issue the following:

- stock options;
- stock appreciation rights;
- restricted stock awards;
- restricted stock units;
- performance based awards; and
- other types of awards in cash or stock to key employees, consultants, and directors.

The maximum number of shares that may be delivered pursuant to the awards granted under the Stock Plan is 11,000,000 shares of common stock. As of December 31, 2014 there were 3,915,594 shares remaining available under the Stock Plan.

Stock Options

As of December 31, 2014, 2013 and 2012, we had no stock options outstanding or exercisable.

Stock-Based Awards

Stock-based awards generally vest over three years. Stock-based compensation expense is recognized net of an estimated forfeiture rate, which is based on historical experience and adjusted, if necessary, in subsequent periods based on actual forfeitures. We recognize share-based compensation expense in the same financial statement line item as cash compensation paid to the respective employees. Tax deduction benefits for awards in excess of recognized compensation costs are reported as a financing cash flow.

We currently issue two types of stock-based awards: restricted stock units (RSUs) and performance share units (PSUs). RSUs entitle a grantee to receive a share of common stock on a specified vesting date. RSUs are service-based awards and compensation expense is recognized ratably over the applicable vesting period. The grant-date fair value of nonvested RSUs is determined based on the closing trading price of the company’s shares on the grant date. RSUs are settled in stock upon vesting. PSUs are performance-based awards as further described under "Performance-Based Awards" below. Compensation costs for PSUs are recognized ratably over a three year performance period. PSUs vest fully at the end of the three year performance period and are typically settled in stock upon vesting.

The following table presents RSUs and PSUs granted, vested and forfeited during 2014 under the Company's Stock Plan:

Nonvested Units	Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2014	3,407,354	$ 4.97
Granted	1,541,395	6.66
Vested	(1,399,874)	5.06
Forfeited	(204,062)	5.44
Nonvested at December 31, 2014	3,344,813	$ 5.66

In 2014, 2013, and 2012 we issued 1,541,395, 2,602,973, and 1,558,347, respectively, of RSUs to selected key personnel. On May 9, 2013 Chris Weber was elected Senior Vice President and Chief Financial Officer of the Company. As part of his employment agreement, he was granted 261,438 RSUs (included in the 2013 amount above). Also, on September 17, 2012, Gary Rich was elected as President, Chief Executive Officer and Director of the Company. As part of his employment agreement, he was granted 349,651 RSUs (included in the 2012 amount above). Both of these awards were granted outside of the Company’s Stock Plan but are subject to substantially the same terms and conditions of other service-based RSUs granted by the Company to its executive officers.

Total stock-based compensation expense recognized relating to RSUs and PSUs for the years ended December 31, 2014, 2013, and 2012 was $9.3 million, $9.4 million, and $7.2 million, respectively, all of which was related to nonvested RSUs and PSUs. The total fair value of the units vested during the years ended December 31, 2014, 2013, and 2012 was $7.1 million, $7.4 million, and $5.2 million, respectively. The fair value of RSUs is determined based on the closing trading price of the Company’s stock on the grant date. The per-share weighted-average grant-date fair value of units granted during the years 2014, 2013, and 2012 was $6.66, $4.77, and $5.37, respectively. Stock-based compensation expense is included in our consolidated statements of operations in both “General and administration expense” and “Operating expenses.”

Nonvested RSUs at December 31, 2014 totaled 3,344,813 and total unrecognized compensation cost related to unamortized nonvested stock awards was $7.7 million as of December 31, 2014. The remaining unrecognized compensation cost related to non-vested stock awards will be amortized over a weighted-average vesting period of approximately 18 months.

Performance-Based Awards

Performance-based awards contain payout conditions which are based on our performance against our peers with regard to relative total shareholder return and relative return on capital employed over a three-year performance period. The effects of these conditions are reflected in the grant-date fair value of the award using a lattice model for valuation. For performance-based awards with graded vesting conditions, 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. For market-based awards that vest at the end of the service period, we recognize compensation expense on a straight-line basis through the end of the service period.

In addition to PSUs, we also issue performance cash units (PCUs), which are typically settled in cash. Each PCU has a nominal value of $100.00. A maximum of 200 percent of the number of PCUs granted may be earned if performance at the maximum level is achieved. Both PSUs and PCUs vest to the extent earned at the end of a three year performance period. We evaluate the terms of each PSU and PCU award to determine if the award should be accounted for as equity or a liability under the stock compensation rules of U.S. GAAP. Compensation costs for PSUs and PCUs are recognized ratably over the performance period.

The following table presents PCUs granted and forfeited under the Company's Stock Plan:

	Year ended December 31,		
	2014	2013	2012
Granted	16,574	18,000	38,429
Forfeited	110	13,358	3,955

Compensation expense recognized related to PCUs for the years ended December 31, 2014, 2013, and 2012 was $3.9 million, $1.8 million, and $0.5 million, respectively.

Note 10 — Reconciliation of Income and Number of Shares Used to Calculate Basic and Diluted Earnings per Share (EPS)

	For the Year Ended December 31, 2014		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 23,451,000	121,186,464	$ 0.19
Effect of dilutive securities:			
Stock options and restricted stock		1,890,184	
Diluted EPS	$ 23,451,000	123,076,648	$ 0.19

	For the Year Ended December 31, 2013		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 27,015,000	119,284,468	$ 0.23
Effect of dilutive securities:			
Stock options and restricted stock		1,940,082	$ (0.01)
Diluted EPS:	$ 27,015,000	121,224,550	$ 0.22

	For the Year Ended December 31, 2012		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 37,313,000	117,721,135	$ 0.32
Effect of dilutive securities:			
Stock options and restricted stock		1,372,455	$ (0.01)
Diluted EPS:	$ 37,313,000	119,093,590	$ 0.31

For the years ended December 31, 2014 and 2013, weighted-average shares outstanding used in our computation of diluted EPS includes the dilutive effect of potential common shares. For the year ended December 31, 2012, all potential common shares have been excluded from the calculation of weighted-average shares outstanding used in our computation of diluted EPS as the company incurred a loss for that year, and therefore, inclusion of potential common shares in the calculation of diluted EPS would be anti-dilutive.

Note 11 — Employee Benefit Plan

The Company sponsors a defined contribution 401(k) plan (Plan) in which substantially all U.S. employees are eligible to participate. The Company matches 100 percent of each participant's pre-tax contributions in an amount not exceeding 4 percent of the participant's compensation and 50 percent of each participant's pre-tax contributions in an amount not exceeding 2 percent of the participant's compensation, up to the maximum amount of contributions allowed by law. The costs of our matching contributions to the Plan were $4.7 million, $3.6 million and $2.8 million in 2014, 2013 and 2012, respectively. Employees become 100 percent vested in the employer match contributions immediately upon participation in the Plan.

Note 12 — Reportable Segments

Our business is comprised of two business lines: (1) Rental Tools Services and (2) Drilling Services. We report our business activities in five reportable segments: (1) Rental Tools, (2) U.S. Barge Drilling, (3) U.S. Drilling, (4) International Drilling, and (5) Technical Services. We eliminate inter-segment revenue and expenses.

The following table represents the results of operations by reportable segment:

	Year Ended December 31,		
Dollars in thousands	2014	2013	2012
Revenues:			
Rental Tools(1)	$ 347,766	$ 310,041	$ 246,900
U.S. Barge Drilling(1)	137,113	136,855	123,672
U.S. Drilling(1)	79,984	66,928	1,387
International Drilling(1)	360,588	333,962	291,772
Technical Services(1)	43,233	26,386	14,030
Construction Contract(1)	—	—	—
Total revenues	968,684	874,172	677,761
Operating income:			
Rental Tools(2)	72,946	91,164	113,899
U.S. Barge Drilling(2)	42,641	51,257	39,608
U.S. Drilling(2)	6,320	(4,484)	(15,168)
International Drilling(2)	28,966	23,732	13,138
Technical Services(2)	3,309	2,050	79
Construction Contract(2)	—	4,728	—
Total operating gross margin	154,182	168,447	151,556
General and administrative expense	(35,016)	(68,025)	(46,257)
Provision for reduction in carrying value of certain assets	—	(2,544)	—
Gain on disposition of assets, net	1,054	3,994	1,974
Total operating income	120,220	101,872	107,273
Interest expense	(44,265)	(47,820)	(33,542)
Interest income	195	2,450	153
Loss on extinguishment of debt	(30,152)	(5,218)	(2,130)
Changes in fair value of derivative positions	—	53	55
Other income (loss)	2,539	1,450	(832)
Income from continuing operations before income taxes	$ 48,537	$ 52,787	$ 70,977

The following table represents capital expenditures and depreciation and amortization by reportable segment:

Dollars in thousands	Year Ended December 31, 2014	2013	2012
Capital expenditures:			
Rental Tools	$ 95,340	$ 76,928	$ 61,958
U.S. Barge Drilling	43,114	23,694	8,808
U.S. Drilling	1,159	1,809	86,786
International Drilling	25,608	39,115	15,240
Corporate	14,292	14,099	18,751
Total capital expenditures	$ 179,513	$ 155,645	$ 191,543
Depreciation and amortization:			
Rental Tools	64,177	55,853	44,117
U.S. Barge Drilling	21,118	14,338	14,492
U.S. Drilling	15,948	16,385	7,017
International Drilling	43,651	47,346	47,354
Technical Services	227	131	37
Construction Contract	—	—	—
Total depreciation and amortization	$ 145,121	$ 134,053	$ 113,017

1) In 2014, our largest customer, Exxon Neftegas Limited (ENL), constituted approximately 18.7 percent of our total consolidated revenues and approximately 41.4 percent of our international drilling segment and 74.3 percent of our technical services segment. In 2013, our largest customer, ENL, constituted approximately 15.6 percent of our total consolidated revenues and approximately 38.3 percent of our international drilling segment and 33.9 percent of our technical services segment. In 2012, our two largest customers, ENL and Schlumberger, constituted approximately 12.0 percent and 10.0 percent, respectively, of our total consolidated revenues and approximately 27.0 percent and 24.0 percent of our international drilling segment, respectively.

2) Operating income is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

The following table represents identifiable assets by reportable segment:

Dollars in Thousands	Year Ended December 31, 2014	2013
Identifiable assets:		
Rental Tools	$ 444,195	$ 350,429
U.S. Barge Drilling	117,344	89,884
U.S. Drilling	308,105	354,208
International Drilling	451,168	460,461
Total identifiable assets	1,320,812	1,254,982
Corporate and other assets[(1)]	199,847	279,774
Total assets	$ 1,520,659	$ 1,534,756

1) This category includes corporate assets as well as minimal assets for our technical services segment primarily related to office furniture and fixtures.

The following table represents selected geographic information:

Operations by Geographic Area:	Year Ended December 31, 2014	2013	2012
Dollars in Thousands			
Revenues:			
Africa and Middle East	$ 128,214	$ 58,416	$ 26,528
Asia Pacific	187,799	170,165	117,392
CIS	61,849	55,165	44,312
Europe	20,296	16,788	—
Latin America	86,651	120,261	103,540
United States	483,875	453,377	385,989
Total revenues	968,684	874,172	677,761
Operating gross margin:			
Africa and Middle East[1]	(16,973)	(383)	(2,027)
Asia Pacific[1]	29,769	21,995	16,550
CIS[1]	19,534	11,888	(9,580)
Europe[1]	11,534	274	—
Latin America[1]	(9,914)	1,140	9,581
United States[1]	120,232	133,533	137,032
Total operating gross margin	154,182	168,447	151,556
Long-lived assets:[2]			
Africa and Middle East	$ 115,713	$ 110,336	
Asia Pacific	43,252	44,606	
CIS	49,951	55,722	
Europe	20,140	82,473	
Latin America	77,136	15,198	
United States	589,748	563,021	
Total long-lived assets	$ 895,940	$ 871,356	

1) Operating gross margin is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

2) Long-lived assets consist of property, plant and equipment, net.

Note 13 — Commitments and Contingencies

The Company has various lease agreements for office space, equipment, vehicles and personal property. These obligations extend through 2025 and are typically non-cancelable. Most leases contain renewal options and certain of the leases contain escalation clauses. Future minimum lease payments at December 31, 2014, under operating leases with non-cancelable terms are as follows:

Dollars in Thousands	Year Ended December 31,
2015	$ 13,188
2016	8,481
2017	7,168
2018	5,857
2019	4,504
Thereafter	8,459
Total	$ 47,657

Total rent expense for all operating leases amounted to $21.8 million, $19.9 million and $11.8 million for 2014, 2013, and 2012, respectively.

Self Insurance

We are self-insured for certain losses relating to workers' compensation, employers' liability, general liability (for onshore liability), protection and indemnity (for offshore liability) and property damage. Our exposure (that is, the retention or deductible) per occurrence is $250,000 for worker's compensation, employer's liability, $500,000 general liability, protection and indemnity and maritime employers' liability (Jones Act). In addition, we assume a $500,000 annual aggregate deductible for protection and indemnity and maritime employers' liability claims. The annual aggregate deductible is reduced by every dollar that exceeds the $500,000 per occurrence retention. We also assume a retention for foreign casualty exposures of $100,000 for workers' compensation, employers' liability, and $1,000,000 for general liability losses and a $100,000 deductible for auto liability claims. For all primary insurances mentioned above, the Company has excess coverage for those claims that exceed the retention and annual aggregate deductible. We maintain actuarially-determined accruals in our consolidated balance sheets to cover the self-insurance retentions.

We have self-insured retentions for certain other losses relating to rig, equipment, property, business interruption and political, war, and terrorism risks which vary according to the type of rig and line of coverage. Political risk insurance is procured for international operations. However, this coverage may not adequately protect us against liability from all potential consequences.

As of December 31, 2014 and 2013, our gross self-insurance accruals for workers' compensation, employers' liability, general liability, protection and indemnity and maritime employers' liability totaled $5.9 million and $5.7 million, respectively and the related insurance recoveries/receivables were $2.0 million and $1.7 million, respectively.

Other Commitments

We have entered into employment agreements with terms of one to two years with certain members of management with automatic one year renewal periods at expiration dates. The agreements provide for, among other things, compensation, benefits and severance payments. The employment agreements also provide for lump sum compensation and benefits in the event of termination within two years following a change in control of the Company.

Contingencies

We are a party to various lawsuits and claims arising out of the ordinary course of business. We estimate the range of our liability related to pending litigation when we believe the amount or range of loss can be estimated. We record our best estimate of a loss when the loss is considered probable. When a liability is probable and there is a range of estimated loss with no best estimate in the range, we record the minimum estimated liability related to the lawsuits or claims. As additional information becomes available, we assess the potential liability related to our pending litigation and claims and revise our estimates. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ significantly from our estimates. In the opinion of management and based on liability accruals provided, our ultimate exposure with respect to these pending lawsuits and claims is not expected to have a material adverse effect on our consolidated financial position or cash flows, although they could have a material adverse effect on our results of operations for a particular reporting period.

Customs Agent and Foreign Corrupt Practices Act (FCPA) Settlement

On April 16, 2013, the Company and the Department of Justice (DOJ) entered into a deferred prosecution agreement (DPA), under which the DOJ will defer for three years prosecuting the Company for criminal violations of the anti-bribery provisions of the FCPA relating to the Company's retention and use of an individual agent in Nigeria with respect to certain customs-related issues, in return for: (i) the Company's acceptance of responsibility for, and agreement not to contest or contradict the truthfulness of, the statement of facts and allegations that have been filed in a United States District Court concurrently with the DPA; (ii) the Company's payment of an approximately 11.76 million fine; (iii) the Company's reaffirming its commitment to compliance with the FCPA and other applicable anti-corruption laws in connection with the Company's operations, and continuing cooperation with domestic and foreign authorities in connection with the matters that are the subject of the DPA; (iv) the Company's commitment to continue to address any identified areas for improvement in the Company's internal controls, policies and procedures relating to compliance with the FCPA and other applicable anti-corruption laws if, and to the extent, not already addressed; and (v) the Company's agreement to report to the DOJ in writing annually during the term of the DPA regarding remediation of the matters that are the subject of the DPA, implementation of any enhanced internal controls, and any evidence of improper payments the Company may have discovered during the term of the agreement. If the Company remains in compliance with the terms of the DPA throughout its effective period, the charge against the Company will be dismissed with prejudice. The Company also settled a related civil complaint filed by the SEC in a United States District Court.

Demand Letter and Derivative Litigation

In April 2010, we received a demand letter from a law firm representing Ernest Maresca. The letter states that Mr. Maresca is one of our stockholders and that he believes that certain of our current and former officers and directors violated their fiduciary duties related to the issues described above under "Customs Agent and Foreign Corrupt Practices Act (FCPA) Settlement." The letter requests that our Board of Directors take action against the individuals in question. In response to this letter, the Board formed a special committee to evaluate the issues raised by the letter and determine a course of action for the Company. The special committee engaged its own counsel for the investigation and evaluated potential claims against all individuals identified in the demand letter. The special committee considered whether pursuing each of the individuals named in the demand letter was in the best interests of the Company based upon a variety of factors, including among others, whether the Company had a potential cause of action against the individual, the defenses the individual might offer to such a claim, the ability of the individual to satisfy any judgment the Company might secure as a result of a claim asserted, and other risks to the Company of pursuing the claims. After taking various factors into account, on July 29, 2013, the special committee recommended to the Board that the Company not pursue any action against the current and former officers and directors named in the demand letter, and the Board accepted such recommendation.

On July 31, 2014, Fuchs Family Trust, a purported stockholder of the Company, filed a complaint under Section 220 of the Delaware Code seeking to inspect the Company's books and records. The action is styled *Fuchs Family Trust v. Parker Drilling Company*, Case No. 9986-VCN, and was filed in the Court of Chancery of the State of Delaware. The complaint alleges that the inspection of records is intended to investigate purported corporate wrongdoing and mismanagement related to the Company's 2013 resolutions of investigations by the U.S. Department of Justice and the Securities and Exchange Commission into certain violations of the Foreign Corrupt Practices Act by Company employees. Plaintiff seeks to compel the records inspection and requests costs, expenses, and attorneys' fees in the event inspection is permitted. The case was heard in November 2014, and the resolution is pending. We do not believe a liability is probable and estimable at this time.

ITS Pre-Acquisition Internal Controls

Our due diligence process with respect to the ITS Acquisition identified certain transactions that suggest that ITS' pre-acquisition internal controls may have failed to prevent violations of potentially applicable international trade and anti-corruption laws, including those of the United Kingdom. We have investigated such violations and have made all identified violations known to relevant authorities. During 2014, we cooperated with all ongoing investigations which resulted in the settlement with the Scottish Civil Recovery Unit of the Scottish Crown Office under United Kingdom anti-bribery laws and regulations. The Company's settlement and recovery of associated legal expenditures was originally included in our escrow account associated with the acquisition; therefore, the settlement had an inconsequential financial impact on our consolidated financial statements.

The Company continues to take proper remediation measures, including seeking any necessary government authorization, in our effort to ensure global compliance with laws and regulations. While it is possible that matters may arise where a contingency may require further accounting considerations, we do not believe that any such matters will have a material impact on our consolidated financial statements.

Note 14 — Related Party Transactions

Consulting Agreement

On December 31, 2013, Robert L. Parker, Jr., our former Executive Chairman, retired as an employee of the Company. Mr. Parker continued to serve as Chairman of the Company's board of directors until the annual meeting of stockholders held in 2014, at which time Mr. Parker was elected to the board for a three-year term.

In connection with Mr. Parker's retirement, the Company and Mr. Parker entered into a Retirement and Separation Agreement dated as of November 1, 2013 (the "Retirement Agreement"). Under the terms of the Retirement Agreement, in 2014 Mr. Parker received a cash bonus of $411,188, a cash payment of $1,096,687 pursuant to the 2010 Long-Term Incentive Program of the Company's Stock Plan, and a severance payment of $2,488,024. The value of benefits provided by the Company to Mr. Parker was $12,876.

In addition, Mr. Parker will be paid $250,000 in each of 2015, 2016 and 2017 in exchange for his agreement to provide additional support to the Company when needed in matters where his historical and industry knowledge, client relationships and related expertise could be of particular benefit to the Company's interests.

Lease Agreement

Effective January 1, 2012, the Company entered into two separate ranch lease agreements under which the Company agreed to pay a daily usage fee per person for utilization of the Cypress Springs Ranch owned by the Robert L. Parker, Sr. and Catherine M. Parker Family Limited Partnership and the Camp Verde Ranch owned by Robert L. Parker, Jr. During 2012, the Company incurred fees of $39,875 and $1,650 for the Cypress Springs Ranch and Camp Verde Ranch, respectively, pursuant to the ranch lease agreements for the right to utilize the premises of the ranches for the purpose of hosting business meetings. During 2013, the Company incurred fees of $14,281 for the Cypress Springs Ranch. Although both of the lease agreements terminated on December 31, 2013, the Company incurred fees of $15,394 and $3,850 in 2014 for the Cypress Springs Ranch and Camp Verde Ranch, respectively pursuant to the Company's use of the ranches for a business meeting.

Other Related Party Agreements

During 2014 and 2013, one of the Company's directors held executive positions at Apache Corporation (Apache), including the positions of President and Chief Corporate Officer, Executive Vice President and Chief Financial Officer and Chief Corporate Officer, until retiring on March 31, 2014. During 2014 and 2013, affiliates of Apache paid affiliates of the Company a total of $34.0 million and $40.8 million, respectively, for performance of drilling services and provision of rental tools. Also during 2013, one of our directors served on the board of directors of Gardner Denver, Inc. (GD). During 2013, affiliates of the Company paid affiliates of GD $0.2 million for goods and services provided to the Company. This information is considered and discussed annually in connection with the Board of Directors' assessment of facts and circumstances that could preclude a determination that such director is independent under the New York Stock Exchange governance listing standards.

We also paid a monthly rental fee to Mr. Robert L. Parker Sr. for various pieces of artwork which were displayed throughout our corporate office. This agreement was terminated as of June 30, 2014. We paid Mr. Parker $15,000 for the year ended December 31, 2014 and $36,000 for each of the years ended December 31, 2013 and 2012 for the artwork rental.

Note 15 — Supplementary Information

The significant components of "Accrued liabilities" on our consolidated balance sheets as of December 31, 2014 and 2013 are presented below:

	Year Ended December 31,	
Dollars in Thousands	2014	2013
Accrued liabilities:		
Accrued Payroll & Related Benefits	$ 32,504	$ 35,671
Accrued Interest Expense	18,171	16,820
Accrued Professional Fees & Other	18,073	21,513
Deferred Mobilization Fees	4,245	8,128
Workers' Compensation Liabilities	2,710	2,721
Total accrued liabilities	$ 75,703	$ 84,853

Note 16 — *Parent, Guarantor, Non-Guarantor Unaudited Consolidating Condensed Financial Statements*

Set forth on the following pages are the consolidating condensed financial statements of Parker Drilling. The Company's 2015 Secured Credit Agreement and Senior Notes are fully and unconditionally guaranteed by substantially all of our direct and indirect domestic subsidiaries other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States, subject to the following customary release provisions:

- in connection with any sale or other disposition of all or substantially all of the assets of that guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) a subsidiary of the Company;
- in connection with any sale of such amount of capital stock as would result in such guarantor no longer being a subsidiary to a person that is not (either before or after giving effect to such transaction) a subsidiary of the Company;
- if the Company designates any restricted subsidiary that is a guarantor as an unrestricted subsidiary;
- if the guarantee by a guarantor of all other indebtedness of the Company or any other guarantor is released, terminated or discharged, except by, or as a result of, payment under such guarantee; or
- upon legal defeasance or covenant defeasance (satisfaction and discharge of the indenture).

There are currently no restrictions on the ability of the restricted subsidiaries to transfer funds to Parker Drilling in the form of cash dividends, loans or advances. Parker Drilling is a holding company with no operations, other than through its subsidiaries. Separate financial statements for each guarantor company are not provided as the company complies with the exception to Rule 3-10(a)(1) of Regulation S-X, set forth in sub-paragraph (f) of such rule. All guarantor subsidiaries are owned 100 percent by the parent company.

We are providing consolidating condensed financial information of the parent, Parker Drilling, the guarantor subsidiaries, and the non-guarantor subsidiaries as of December 31, 2014 and December 31, 2013 and for the years ended December 31, 2014, 2013, and 2012. The consolidating condensed financial statements present investments in both consolidated and unconsolidated subsidiaries using the equity method of accounting.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 506,205	$ 640,147	$ (177,668)	$ 968,684
Operating expenses	—	279,396	567,653	(177,668)	669,381
Depreciation and amortization	—	87,248	57,873	—	145,121
Total operating gross margin	—	139,561	14,621	—	154,182
General and administration expense (1)	(302)	(33,035)	(1,679)	—	(35,016)
Gain (loss) on disposition of assets, net	(79)	1,156	(23)	—	1,054
Total operating income (loss)	(381)	107,682	12,919	—	120,220
Other income and (expense):					
Interest expense	(46,527)	(148)	(7,692)	10,102	(44,265)
Interest income	1,478	623	8,196	(10,102)	195
Loss on extinguishment of debt	(30,152)	—	—	—	(30,152)
Other	—	2,810	(271)	—	2,539
Equity in net earnings of subsidiaries	67,399	—	—	(67,399)	—
Total other income (expense)	(7,802)	3,285	233	(67,399)	(71,683)
Income (loss) before income taxes	(8,183)	110,967	13,152	(67,399)	48,537
Income tax expense (benefit):					
Current	(17,702)	24,106	16,163	—	22,567
Deferred	(13,932)	16,949	(1,508)	—	1,509
Income tax expense (benefit)	(31,634)	41,055	14,655	—	24,076
Net income (loss)	23,451	69,912	(1,503)	(67,399)	24,461
Less: Net income attributable to noncontrolling interest	—	—	1,010	—	1,010
Net income (loss) attributable to controlling interest	$ 23,451	$ 69,912	$ (2,513)	$ (67,399)	$ 23,451

(1) General and administration expenses for field operations are included in operating expenses.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 468,073	$ 549,295	$ (143,196)	$ 874,172
Operating expenses	—	252,211	462,657	(143,196)	571,672
Depreciation and amortization	—	77,416	56,637	—	134,053
Total operating gross margin	—	138,446	30,001	—	168,447
General and administration expense (1)	(202)	(67,083)	(740)	—	(68,025)
Provision for reduction in carrying value of certain assets	—	—	(2,544)	—	(2,544)
Gain on disposition of assets, net	—	1,759	2,235	—	3,994
Total operating income (loss)	(202)	73,122	28,952	—	101,872
Other income and (expense):					
Interest expense	(51,439)	(335)	(9,930)	13,884	(47,820)
Interest income	3,824	1,761	10,749	(13,884)	2,450
Loss on extinguishment of debt	(5,218)	—	—	—	(5,218)
Changes in fair value of derivative positions	53	—	—	—	53
Other	(1)	(143)	1,594	—	1,450
Equity in net earnings of subsidiaries	55,430	—	—	(55,430)	—
Total other income (expense)	2,649	1,283	2,413	(55,430)	(49,085)
Income (loss) before income taxes	2,447	74,405	31,365	(55,430)	52,787
Income tax expense (benefit):					
Current	(21,431)	18,737	15,603	—	12,909
Deferred	(3,137)	19,454	(3,618)	—	12,699
Income tax expense (benefit)	(24,568)	38,191	11,985	—	25,608
Net income (loss)	27,015	36,214	19,380	(55,430)	27,179
Less: Net income attributable to noncontrolling interest	—	—	164	—	164
Net income (loss) attributable to controlling interest	$ 27,015	$ 36,214	$ 19,216	$ (55,430)	$ 27,015

(1) General and administration expenses for field operations are included in operating expenses.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 393,738	$ 385,279	$ (101,256)	$ 677,761
Operating expenses	—	184,946	329,498	(101,256)	413,188
Depreciation and amortization	—	65,354	47,663	—	113,017
Total operating gross margin	—	143,438	8,118	—	151,556
General and administration expense (1)	(182)	(45,758)	(317)	—	(46,257)
Gain on disposition of assets, net	—	775	1,199	—	1,974
Total operating income (loss)	(182)	98,455	9,000	—	107,273
Other income and (expense):					
Interest expense	(37,326)	(151)	(8,739)	12,674	(33,542)
Interest income	9,863	5,073	41,999	(56,782)	153
Loss on extinguishment of debt	(2,130)	—	—	—	(2,130)
Changes in fair value of derivative positions	55	—	—	—	55
Other	—	(206)	(626)	—	(832)
Equity in net earnings of subsidiaries	43,884	—	—	(43,884)	—
Total other income and (expense)	14,346	4,716	32,634	(87,992)	(36,296)
Income (loss) before income taxes	14,164	103,171	41,634	(87,992)	70,977
Income tax expense (benefit):					
Current	(25,406)	32,781	10,667	—	18,042
Deferred	2,257	15,429	(1,849)	—	15,837
Total income tax expense (benefit)	(23,149)	48,210	8,818	—	33,879
Net income (loss)	37,313	54,961	32,816	(87,992)	37,098
Less: Net (loss) attributable to noncontrolling interest	—	—	(215)	—	(215)
Net income (loss) attributable to controlling interest	$ 37,313	$ 54,961	$ 33,031	$ (87,992)	$ 37,313

1) General and administration expenses for field operations are included in operating expenses.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income (loss)	$ 23,451	$ 69,912	$ (1,503)	$ (67,399)	$ 24,461
Other comprehensive gain (loss), net of tax:					
Currency translation difference on related borrowings	—	—	(4,870)	—	$ (4,870)
Currency translation difference on foreign currency net investments	—	—	2,147	—	$ 2,147
Total other comprehensive gain (loss), net of tax:	—	—	(2,723)	—	(2,723)
Comprehensive income (loss)	23,451	69,912	(4,226)	(67,399)	21,738
Comprehensive (income) loss attributable to noncontrolling interest	—	—	(673)	—	(673)
Comprehensive income (loss) attributable to controlling interest	$ 23,451	$ 69,912	$ (4,899)	$ (67,399)	$ 21,065

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income (loss)	$ 27,015	$ 36,214	$ 19,380	$ (55,430)	$ 27,179
Other comprehensive gain, net of tax:					
Currency translation difference on related borrowings	—	—	(1,525)	—	(1,525)
Currency translation difference on foreign currency net investments	—	—	3,051	—	3,051
Total other comprehensive gain, net of tax:	—	—	1,526	—	1,526
Comprehensive income (loss)	27,015	36,214	20,906	(55,430)	28,705
Comprehensive (income) loss attributable to noncontrolling interest	—	—	198	—	198
Comprehensive income (loss) attributable to controlling interest	$ 27,015	$ 36,214	$ 21,104	$ (55,430)	$ 28,903

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income (loss)	$ 37,313	$ 54,961	$ 32,816	$ (87,992)	$ 37,098
Other comprehensive gain, net of tax:					
Currency translation difference on related borrowings	—	—	—	—	—
Currency translation difference on foreign currency net investments	—	—	—	—	—
Comprehensive income (loss)	37,313	54,961	32,816	(87,992)	37,098
Comprehensive (income) loss attributable to noncontrolling interest	—	—	215	—	215
Comprehensive income (loss) attributable to controlling interest	$ 37,313	$ 54,961	$ 33,031	$ (87,992)	$ 37,313

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED BALANCE SHEET
(Dollars in Thousands)
(Unaudited)

	December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 36,728	$ 13,546	$ 58,182	$ —	$ 108,456
Accounts and notes receivable, net	(33)	96,100	174,885	—	270,952
Rig materials and supplies	—	(1,473)	49,416	—	47,943
Deferred costs	—	—	5,673	—	5,673
Deferred income taxes	—	6,131	1,345	—	7,476
Other tax assets	19,885	(18,273)	9,111	—	10,723
Other current assets	—	7,999	10,557	—	18,556
Total current assets	56,580	104,030	309,169	—	469,779
Property, plant and equipment, net	(19)	589,055	306,904	—	895,940
Investment in subsidiaries and intercompany advances	3,060,867	2,441,527	2,464,502	(7,966,896)	—
Other noncurrent assets	(440,918)	490,597	272,823	(167,562)	154,940
Total assets	$ 2,676,510	$ 3,625,209	$ 3,353,398	$ (8,134,458)	$ 1,520,659
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 10,000	$ —	$ —	$ —	10,000
Accounts payable and accrued liabilities	77,603	71,645	309,344	(304,113)	154,479
Accrued income taxes	(4,061)	10,109	8,138	—	14,186
Total current liabilities	83,542	81,754	317,482	(304,113)	178,665
Long-term debt	605,000	—	—	—	605,000
Other long-term liabilities	2,867	7,135	8,663	—	18,665
Long-term deferred tax liability	—	56,105	(3,990)	—	52,115
Intercompany payables	1,322,172	1,311,405	1,204,768	(3,838,345)	—
Total Liabilities	2,013,581	1,456,399	1,526,923	(4,142,458)	854,445
Total Equity	662,929	2,168,810	1,826,475	(3,992,000)	666,214
Total liabilities and stockholders' equity	$ 2,676,510	$ 3,625,209	$ 3,353,398	$ (8,134,458)	$ 1,520,659

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED BALANCE SHEET
(Dollars in Thousands)
(Unaudited)

	December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 88,697	$ 8,310	$ 51,682	$ —	$ 148,689
Accounts and notes receivable, net	—	101,299	156,590	—	257,889
Rig materials and supplies	—	3,002	38,779	—	41,781
Deferred costs	—	—	13,682	—	13,682
Deferred income taxes	(57)	8,435	1,562	—	9,940
Other tax assets	54,524	(46,770)	16,325	—	24,079
Other current assets	—	9,089	14,134	—	23,223
Total current assets	143,164	83,365	292,754	—	519,283
Property, plant and equipment, net	60	562,148	309,148	—	871,356
Investment in subsidiaries and intercompany advances	1,906,128	(336,570)	1,667,937	(3,237,495)	—
Other noncurrent assets	(457,954)	468,864	250,983	(117,776)	144,117
Total assets	$ 1,591,398	$ 777,807	$ 2,520,822	$ (3,355,271)	$ 1,534,756
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 25,000	$ —	$ —	$ —	$ 25,000
Accounts payable and accrued liabilities	75,268	92,546	261,436	(254,364)	174,886
Accrued income taxes	—	725	6,541	—	7,266
Total current liabilities	100,268	93,271	267,977	(254,364)	207,152
Long-term debt	628,781	—	—	—	628,781
Other long-term liabilities	5,037	6,743	15,134	—	26,914
Long-term deferred tax liability	—	51,747	(12,980)	—	38,767
Intercompany payables	227,504	291,783	422,645	(941,932)	—
Total Liabilities	961,590	443,544	692,776	(1,196,296)	901,614
Total Equity	629,808	334,263	1,828,046	(2,158,975)	633,142
Total liabilities and stockholders' equity	$ 1,591,398	$ 777,807	$ 2,520,822	$ (3,355,271)	$ 1,534,756

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 23,451	$ 69,912	$ (1,503)	$ (67,399)	24,461
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	87,248	57,873	—	145,121
Loss on extinguishment of debt	30,152	—	—	—	30,152
Gain on disposition of assets	79	(1,156)	23	—	(1,054)
Deferred income tax expense	(13,932)	16,949	(1,508)	—	1,509
Expenses not requiring cash	11,978	(710)	8,063	—	19,331
Equity in net earnings of subsidiaries	(67,399)	—	—	67,399	—
Change in accounts receivable	32	11,937	(24,207)	—	(12,238)
Change in other assets	35,438	(56,673)	(3,154)	—	(24,389)
Change in accrued income taxes	(12,474)	11,107	(6,290)	—	(7,657)
Change in liabilities	2,336	(20,492)	45,387	—	27,231
Net cash provided by operating activities	9,661	118,122	74,684	—	202,467
Cash flows from investing activities:					
Capital expenditures	—	(125,260)	(54,253)	—	(179,513)
Proceeds from the sale of assets	—	2,594	3,344	—	5,938
Net cash (used in) investing activities	—	(122,666)	(50,909)	—	(173,575)
Cash flows from financing activities:					
Proceeds from debt issuance	400,000	—	—	—	400,000
Repayment of long term debt	(425,000)	—	—	—	(425,000)
Repayment of term loan	(10,000)	—	—	—	(10,000)
Payment of debt issuance costs	(7,630)	—	—	—	(7,630)
Payment of debt extinguishment costs	(26,214)	—	—	—	(26,214)
Excess tax benefit from stock-based compensation	(281)	—	—	—	(281)
Intercompany advances, net	7,495	9,780	(17,275)	—	—
Net cash provided by (used in) financing activities	(61,630)	9,780	(17,275)	—	(69,125)
Net change in cash and cash equivalents	(51,969)	5,236	6,500	—	(40,233)
Cash and cash equivalents at beginning of year	88,697	8,310	51,682	—	148,689
Cash and cash equivalents at end of year	$ 36,728	$ 13,546	$ 58,182	$ —	$ 108,456

See accompanying notes to unaudited consolidated condensed financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 27,015	$ 36,214	$ 19,380	$ (55,430)	$ 27,179
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	77,416	56,637	—	134,053
Loss on extinguishment of debt	5,218	—	—	—	5,218
Gain on disposition of assets	—	(1,759)	(2,235)	—	(3,994)
Deferred income tax expense	(3,137)	19,454	(3,618)	—	12,699
Provision for reduction in carrying value of certain assets	—	—	2,544	—	2,544
Expenses not requiring cash	13,173	12	4,579	—	17,764
Equity in net earnings of subsidiaries	(55,430)	—	—	55,430	—
Change in accounts receivable	(7)	(12,888)	(20,617)	—	(33,512)
Change in other assets	74,411	(85,520)	487	—	(10,622)
Change in accrued income taxes	6,617	(1,052)	4,889	—	10,454
Change in liabilities	6,934	(877)	(6,343)	—	(286)
Net cash provided by operating activities	74,794	31,000	55,703	—	161,497
Cash flows from investing activities:					
Capital expenditures	—	(94,269)	(61,376)	—	(155,645)
Proceeds from the sale of assets	—	3,725	4,493	—	8,218
Acquisition of ITS, net of cash acquired	—	(6,903)	(111,088)	—	(117,991)
Net cash provided by (used in) investing activities	—	(97,447)	(167,971)	—	(265,418)
Cash flows from financing activities:					
Proceeds from debt issuance	350,000	—	—	—	350,000
Repayment of long term debt	(125,000)	—	—	—	(125,000)
Repayment of term loan	(50,000)	—	—	—	(50,000)
Payment of debt issuance costs	(11,172)	—	—	—	(11,172)
Excess tax benefit from stock-based compensation	896	—	—	—	896
Intercompany advances, net	(193,072)	63,734	129,338	—	—
Net cash provided by (used in) financing activities	(28,348)	63,734	129,338	—	164,724
Net change in cash and cash equivalents	46,446	(2,713)	17,070	—	60,803
Cash and cash equivalents at beginning of year	42,251	11,023	34,612	—	87,886
Cash and cash equivalents at end of year	$ 88,697	$ 8,310	$ 51,682	$ —	$ 148,689

See accompanying notes to unaudited consolidated condensed financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 37,313	$ 54,961	$ 32,816	$ (87,992)	$ 37,098
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	65,354	47,663	—	113,017
Loss on extinguishment of debt	2,130	—	—	—	2,130
Gain on disposition of assets	—	(775)	(1,199)	—	(1,974)
Deferred income tax expense	2,257	15,429	(1,849)	—	15,837
Expenses not requiring cash	16,558	33,644	(27,602)	—	22,600
Equity in net earnings of subsidiaries	(43,884)	—	—	43,884	—
Change in accounts receivable	(445)	(1,788)	17,474	—	15,241
Change in other assets	1,649	2,060	(9,200)	—	(5,491)
Change in accrued income taxes	(4,055)	220	(2,267)	—	(6,102)
Change in liabilities	3,914	(4,158)	(2,413)	—	(2,657)
Net cash provided by (used in) operating activities	15,437	164,947	53,423	(44,108)	189,699
Cash flows from investing activities:					
Capital expenditures	—	(176,333)	(15,210)	—	(191,543)
Proceeds from the sale of assets	—	2,062	1,875	—	3,937
Intercompany dividend payment	(8,387)	(4,357)	(31,364)	44,108	—
Net cash provided by (used in) investing activities	(8,387)	(178,628)	(44,699)	44,108	(187,606)
Cash flows from financing activities:					
Proceeds from debt issuance	130,000	—	—	—	130,000
Proceeds from draw on revolver credit facility	7,000	—	—	—	7,000
Paydown on senior notes	(125,000)	—	—	—	(125,000)
Paydown on term note	(18,000)	—	—	—	(18,000)
Payment of debt issuance costs	(4,859)	—	—	—	(4,859)
Payment of debt extinguishment costs	(555)	—	—	—	(555)
Excess tax benefit from stock-based compensation	(662)	—	—	—	(662)
Intercompany advances, net	(8,393)	20,492	(12,099)	—	—
Net cash provided by (used in) financing activities	(20,469)	20,492	(12,099)	—	(12,076)
Net change in cash and cash equivalents	(13,419)	6,811	(3,375)	—	(9,983)
Cash and cash equivalents at beginning of year	55,670	4,212	37,987	—	97,869
Cash and cash equivalents at end of year	$ 42,251	$ 11,023	$ 34,612	$ —	$ 87,886

See accompanying notes to unaudited consolidated condensed financial statements.

Note 17 — Selected Quarterly Financial Data

Year 2014	Quarter First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$ 229,225	$ 254,234	$ 242,012	$ 243,213	$ 968,684
Operating gross margin	$ 28,863	$ 43,485	$ 45,066	$ 36,768	$ 154,182
Operating income	$ 19,770	$ 37,497	$ 35,239	$ 27,714	$ 120,220
Net income (loss) attributable to controlling interest	$ (12,549)	$ 15,681	$ 12,566	$ 7,753	$ 23,451
Basic earnings per share — net income (loss)	$ (0.10)	$ 0.13	$ 0.10	$ 0.06	$ 0.19
Diluted earnings per share — net income (loss)	$ (0.10)	$ 0.13	$ 0.10	$ 0.06	$ 0.19

Year 2013	Quarter First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$ 167,135	$ 225,954	$ 237,762	$ 243,321	$ 874,172
Operating gross margin (1)	$ 20,877	$ 50,273	$ 48,733	$ 48,564	$ 168,447
Operating income	$ 9,180	$ 28,587	$ 35,589	$ 28,516	$ 101,872
Net income attributable to controlling interest	$ 592	$ 8,281	$ 7,970	$ 10,172	$ 27,015
Basic earnings per share — net income	$ —	$ 0.07	$ 0.07	$ 0.08	$ 0.23
Diluted earnings per share — net income	$ —	$ 0.07	$ 0.07	$ 0.08	$ 0.22

1) Expenses related to our U.S. barge drilling segment were found to be incorrectly included in our general and administrative expense during the first through third quarters of 2013. These expenses have been appropriately reclassified to be included as part of the segment operating expenses, therefore our operating gross margin for each of the first three quarters of 2013 will not agree to the respective 10-Q reports for 2013 only.

Note 18 — Recent Accounting Pronouncements

On May 28, 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers. This ASU supersedes the revenue recognition requirements in Accounting Standards Codification 605 - Revenue Recognition and most industry-specific guidance throughout the Codification. The standard requires that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This ASU is effective on January 1, 2017 and should be applied retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the ASU recognized at the date of initial application. We are in the process of assessing the impact of the adoption of ASU 2014-09 on our financial position, results of operations and cash flows. We have not yet selected a transition method nor have we determined the effect of the standard on our ongoing financial reporting.

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU requires an entity to present an unrecognized tax benefit as a reduction of a deferred tax asset for a net operating loss (NOL) carryforward, or similar tax loss or tax credit carryforward, rather than as a liability when: (1) the uncertain tax position would reduce the NOL or other carryforward under the tax law of the applicable jurisdiction and (2) the entity intends to use the deferred tax asset for that purpose. This accounting guidance was effective for our first quarter in fiscal 2014 and did not have a material impact on our condensed consolidated financial statements.

Note 19 — Subsequent Events

Subsequent to year end we increased our liquidity by entering into the 2015 Second Amended and Restated Credit Agreement on January 26, 2015. See Note 6 - Long Term Debt for further discussion.

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

None.

Item 9A. Controls and Procedures

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 as amended (the Exchange Act), 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 on 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 provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and is (2) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States,
- provide reasonable assurance that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and
- 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 risk that controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate.

The Company's management with the participation of the chief executive officer and chief financial officer assessed the effectiveness of our internal control over financial reporting as of December 31, 2014 based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management's assessment included evaluation of the design and testing of the operational effectiveness of our internal control over financial reporting. Management reviewed the results of its assessment with the audit committee of the board of directors.

Based on that assessment and those criteria, management has concluded that our internal control over financial reporting was effective as of December 31, 2014.

KPMG LLP, our independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report Form 10-K, has issued a report with respect to our internal control over financial reporting as of December 31, 2014.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information with respect to directors can be found under the captions “Item 1 — Election of Directors” and “Board of Directors” in our 2015 Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2015. Such information is incorporated herein by reference.

Information with respect to executive officers can be found in Item 1. Business - Executive Officers of this Form 10-K.

Information with respect to our audit committee and audit committee financial expert can be found under the caption “The Audit Committee” of our 2015 Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2015 and is incorporated herein by reference.

The information in our 2015 Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2015 set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” is incorporated herein by reference.

We have adopted the Parker Drilling Code of Conduct (CC) which includes a code of ethics that is applicable to the chief executive officer, chief financial officer, controller and other senior financial personnel as required by the SEC. The CC includes provisions that will ensure compliance with the code of ethics required by the SEC and with the minimum requirements under the corporate governance listing standards of the NYSE. The CC is publicly available on our website at http://www.parkerdrilling.com. If any waivers of the CC occur that apply to a director, the chief executive officer, the chief financial officer, the controller or senior financial personnel or if the Company materially amends the CC, we will disclose the nature of the waiver or amendment on the website and in a current report on Form 8-K within four business days.

Item 11. Executive Compensation

The information under the captions “Executive Compensation,” “Fees and Benefit Plans for Non-Employee Directors,” “2014 Director Compensation Table,” and “Compensation Committee Report” in our 2015 Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2015 is incorporated herein by reference.

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

The information required by this item is hereby incorporated by reference to the information appearing under the captions “Security Ownership of Officers, Directors and Principal Stockholders” and “Equity Compensation Plan Information” in our 2015 Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2015.

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

The information required by this item is hereby incorporated by reference to such information appearing under the captions “Certain Relationships and Related Party Transactions” and “Director Independence Determination” in our 2015 Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2015.

Item 14. Principal Accounting Fees and Services

The information required by this item is hereby incorporated by reference to the information appearing under the captions “Audit and Non-Audit Fees” and “Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accounting Firm” in our 2015 Proxy Statement for the Annual Meeting of the Stockholders to be held on May 7, 2015.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements of Parker Drilling Company and subsidiaries which are included in Part II, Item 8:

(3) Exhibits:

Exhibit Number		Description
2.1	—	Sale and Purchase Agreement, dated April 22, 2013, among ITS Tubular Services (Holdings) Limited, as Seller, Ian David Green, John Bruce Cartwright and Graham Douglas Frost, as joint administrators of the Seller, ITS Holdings, Inc. and PD International Holdings C.V., Parker Drilling Offshore Corporation and Parker Drilling Company (Incorporated by reference to Exhibit 10.1 to Parker Drilling Company's Current Report on Form 8-K filed on April 23, 2013).
3.1	—	Restated Certificate of Incorporation of the Company, as amended on May 16, 2007 (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007).
3.2	—	By-laws of Parker Drilling Company, as amended and restated as of July 31, 2014 (Incorporated by reference to Exhibit 3.1 to Parker Drilling Company's Current Report on Form 8-K filed on August 1, 2014).
4.1	—	Indenture, dated July 30, 2013, between Parker Drilling Company, the subsidiary guarantors from time to time parties hereto, as, collectively, Guarantors, and The Bank of New York Mellon Trust Company, N.A. as Trustee (Incorporated by reference to Exhibit 10.3 to Parker Drilling Company's Current Report on Form 8-K filed on July 25, 2013).
4.2	—	Form of 7.500% Senior Note due 2020 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on July 31, 2013).
4.3	—	Indenture, dated January 22, 2014, among Parker Drilling Company, the Guarantors and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K file on January 28, 2014).
4.4	—	Form of 6.750% Senior Note due 2018 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on January 28, 2014).
10.1	—	Parker Drilling Company Incentive Compensation Plan (as amended and restated effective January 1, 2009) (incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 1, 2011)*
10.2	—	Parker Drilling Company 2010 Long-Term Incentive Plan (incorporated by reference to Annex A to the Company's Definitive Proxy Statement filed on March 16, 2010).*

10.3	—	Form of Parker Drilling Company Restricted Stock Unit Incentive Agreement under the 2010 LTIP (incorporated by reference to Exhibit 10.18 to the Company’s Annual Report on Form 10-K filed on March 1, 2011).*
10.4	—	Form of Parker Drilling Company Performance Unit Award Incentive Agreement under the 2010 LTIP (incorporated by reference to Exhibit 10.19 to the Company’s Annual Report on Form 10-K filed on March 1, 2011).*
10.5	—	Parker Drilling Company 2010 Long-Term Incentive Plan (as amended and restated effective May 8, 2013) (incorporated by reference to Annex A to the Company’s Definitive Proxy Statement filed on March 28, 2013).*
10.6	—	Form of Parker Drilling Company Restricted Stock Unit Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.7	—	Form of Parker Drilling Company Performance Stock Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.8	—	Form of Parker Drilling Company Performance Cash Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.9	—	Form of Indemnification Agreement entered into between Parker Drilling Company and each director and executive officer of Parker Drilling Company (incorporated by reference to Exhibit 10(g) to the Company’s Annual Report on Form 10-K filed on March 20, 2003).*
10.10	—	Employment Agreement dated December 6, 2010 between Parker Drilling Company and Philip Agnew.*
10.11	—	Employment Agreement between Mr. Jon-Al Duplantier and Parker Drilling Company, effective March 21, 2011 (incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K filed on March 25, 2011).*
10.12	—	Employment Agreement dated August 15, 2011 between Parker Drilling Company and David Farmer.*
10.13	—	First Amendment dated August 29, 2011 to Employment Agreement between Parker Drilling Company and Philip Agnew.*
10.14	—	First Amendment dated August 29, 2011 to Employment Agreement between Mr. Jon-Al Duplantier and Parker Drilling Company, effective March 21, 2011 (incorporated by reference to Exhibit 10.4 to the Company’s Current Report on Form 8-K filed on August 30, 2011).*
10.15	—	Employment Agreement, dated as of September 17, 2012, by and between Parker Drilling Company and Gary Rich (incorporated by reference to Exhibit 10.23 to the Company’s Current Report on Form 8-K filed on September 24, 2012).*
10.16	—	Form of Restricted Stock Unit Incentive Agreement between Parker Drilling Company and Gary Rich (incorporated by reference to Exhibit 10.23 to the Company’s Current Report on Form 8-K filed on September 24, 2012).*
10.17	—	Employment Agreement dated May 3, 2013 between Parker Drilling Company and Christopher Weber (Incorporated by reference to Exhibit 10.1 to Parker Drilling Company's Current Report on Form 8-K filed on May 14, 2013).*
10.18	—	Form of Restricted Stock Unit Incentive Agreement between Parker Drilling Company and Christopher Weber (Incorporated by reference to Exhibit 10.2 to Parker Drilling Company's Current Report on Form 8-K filed on May 14, 2013).*

10.19	—	Retirement and Separation Agreement, dated November 1, 2013, between Parker Drilling Company and Robert L. Parker, Jr. (Incorporated by reference to Exhibit 10.1 to Parker Drilling Company's Current Report on Form 8-K filed on November 4, 2013).*
10.20	—	Second Amended and Restated Credit Agreement, dated January 26, 2015, among Parker Drilling Company, as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, Barclays Bank PLC, as Documentation Agent, and the other lenders and L/C issuers from time to time party thereto.
12.1	—	Computation of Ratio of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23.1	—	Consent of KPMG LLP — Independent Registered Public Accounting Firm.
31.1	—	Gary Rich, President and Chief Executive Officer, Rule 13a-14(a)/15d-14(a) Certification.
31.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Rule 13a-14(a)/15d-14(a) Certification.
32.1	—	Gary Rich, President and Chief Executive Officer, Section 1350 Certification.
32.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Section 1350 Certification.
101.INS	—	XBRL Instance Document.
101.SCH	—	XBRL Taxonomy Schema Document.
101.CAL	—	XBRL Calculation Linkbase Document.
101.LAB	—	XBRL Label Linkbase Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

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* — Management contract, compensatory plan or agreement.

PARKER DRILLING COMPANY AND SUBSIDIARIES

Schedule II—Valuation and Qualifying Accounts

Classifications	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of year
Dollars in Thousands					
Year ended December 31, 2014					
Allowance for bad debt	$ 12,853	$ 5,248	$ —	$ (6,913)	$ 11,188
Allowance for obsolete rig materials and supplies	$ 3,445	—	$ 1	$ (2,916)	$ 530
Deferred tax valuation allowance	$ 6,827	$ 2,800	$ 295	$ —	$ 9,922
Year ended December 31, 2013					
Allowance for bad debt	$ 8,117	$ 5,092	$ 5,861	$ (6,217)	$ 12,853
Allowance for obsolete rig materials and supplies	$ 312	—	$ 3,586	$ (453)	$ 3,445
Deferred tax valuation allowance	$ 4,805	$ 2,010	$ 12	$ —	$ 6,827
Year ended December 31, 2012					
Allowance for bad debt	$ 1,544	$ 4,264	$ 3,195	$ (886)	$ 8,117
Allowance for obsolete rig materials and supplies	$ 316	$ —	$ —	$ (4)	$ 312
Deferred tax valuation allowance	$ 6,467	$ (1,662)	$ —	$ —	$ 4,805

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PARKER DRILLING COMPANY

By: /s/ Christopher T. Weber

Christopher T. Weber
Senior Vice President and Chief Financial Officer

Date: February 25, 2015

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
By: /s/ Gary G. Rich Gary G. Rich	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	February 25, 2015
By: /s/ Christopher T. Weber Christopher T. Weber	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2015
By: /s/ Leslie K. Nagy Leslie K. Nagy	Controller and Principal Accounting Officer (Principal Accounting Officer)	February 25, 2015
By: /s/ Jonathan M. Clarkson Jonathan M. Clarkson	Director	February 25, 2015
By: /s/ George J. Donnelly George J. Donnelly	Director	February 25, 2015
By: /s/ Robert W. Goldman Robert W. Goldman	Director	February 25, 2015
By: /s/ Gary R. King Gary R. King	Director	February 25, 2015
By: /s/ Robert L. Parker Jr. Robert L. Parker Jr.	Director	February 25, 2015
By: /s/ Richard D. Paterson Richard D. Paterson	Director	February 25, 2015
By: /s/ Roger B. Plank Roger B. Plank	Director	February 25, 2015
By: /s/ R. Rudolph Reinfrank R. Rudolph Reinfrank	Director	February 25, 2015

INDEX TO EXHIBITS

Exhibit Number		Description
10.6	—	Form of Parker Drilling Company Restricted Stock Unit Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.7	—	Form of Parker Drilling Company Performance Stock Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.8	—	Form of Parker Drilling Company Performance Cash Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.10	—	Employment Agreement dated December 6, 2010 between Parker Drilling Company and Philip Agnew.*
10.12	—	Employment Agreement dated August 15, 2011 between Parker Drilling Company and David Farmer.*
10.13	—	First Amendment dated August 29, 2011 to Employment Agreement between Parker Drilling Company and Philip Agnew.*
10.20	—	Second Amended and Restated Credit Agreement, dated January 26, 2015, among Parker Drilling Company, as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, Barclays Bank PLC, as Documentation Agent, and the other lenders and L/C issuers from time to time party thereto.
12.1	—	Computation of Ratio of Earnings to Fixed Charges
21	—	Subsidiaries of the Registrant.
23.1	—	Consent of KPMG LLP — Independent Registered Public Accounting Firm.
31.1	—	Gary G. Rich, President and Chief Executive Officer, Rule 13a-14(a)/15d-14(a) Certification.
31.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Rule 13a-14(a)/15d-14(a) Certification.
32.1	—	Gary G. Rich, President and Chief Executive Officer, Section 1350 Certification.
32.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Section 1350 Certification.
101.INS	—	XBRL Instance Document.
101.SCH	—	XBRL Taxonomy Schema Document.
101.CAL	—	XBRL Calculation Linkbase Document.
101.LAB	—	XBRL Label Linkbase Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

BOARD OF DIRECTORS

Gary G. Rich
Chairman of the Board of Directors,
President and Chief Executive Officer
Parker Drilling Company

Jonathan M. Clarkson
Retired Chairman, President
and Chief Executive Officer
Texas Capital Bank

George J. Donnelly
Managing Partner
Lilo Ventures

Robert W. Goldman
Retired Chief Financial Officer
Conoco, Inc.

Gary R. King
Managing Partner
Matrix Partnership

Robert L. Parker, Jr.
Retired Chairman
Parker Drilling Company

Richard D. Paterson
Retired Managing Partner
PriceWaterhouseCoopers, LLP

Roger B. Plank
Retired President and
Chief Corporate Officer
Apache Corporation

R. Rudolph Reinfrank
Managing General Partner
Riverford Partners, LLC

Zaki Selim
Retired President of Oilfield Services,
Middle East and Asia
Schlumberger Limited

CEO AND CFO CERTIFICATIONS

Parker Drilling Company submitted the annual CEO certification to the NYSE as required under the corporate governance rules of the NYSE. Parker Drilling Company also filed as an exhibit to its 2014 Annual Report on Form 10-K the CEO and CFO certifications required under Section 302 of the Sarbanes-Oxley Act of 2002.

EXECUTIVE OFFICERS

Gary G. Rich
Chairman of the Board of Directors,
President and Chief Executive Officer

Christopher T. Weber
Senior Vice President and
Chief Financial Officer

Jon-Al Duplantier
Senior Vice President,
Chief Administrative Officer and
General Counsel

Philip L. Agnew, III
Senior Vice President and
Chief Technical Officer

David R. Farmer
Senior Vice President,
Europe, Middle East and Asia

OTHER OFFICERS

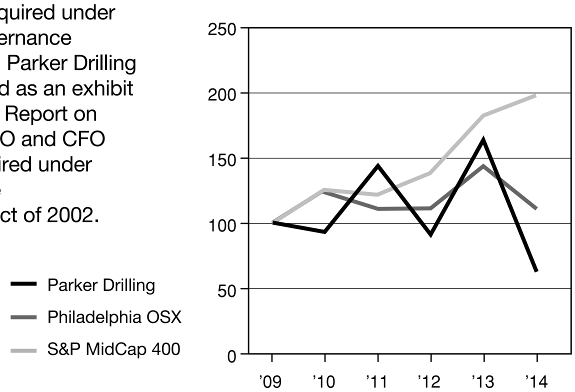
Philip A. Schlom
Vice President, Global Compliance
and Internal Audit

Leslie K. Nagy
Principal Accounting Officer and Controller

David W. Tucker
Treasurer

PERFORMANCE GRAPH

The following performance graph compares cumulative total shareholder returns on Parker Drilling Company's common stock to the Philadelphia Oil Service Index (Philadelphia OSX) and the S&P MidCap 400 stock index, calculated as of the end of each year during the period beginning December 31, 2009 and ending on December 31, 2014. The graph assumes $100 was invested on December 31, 2009 in the Company's common stock and in each of the referenced indices.



CORPORATE INFORMATION

Corporate Headquarters
Parker Drilling Company
5 Greenway Plaza, Suite 100
Houston, Texas 77046
Telephone: (281) 406-2000
www.parkerdrilling.com

Notice of Annual Meeting
The Annual Meeting of Stockholders
will be held at 9 A.M. CDT
May 7, 2015
DoubleTree by Hilton Hotel–Greenway Plaza
6 East Greenway Plaza
Houston, Texas 77046

Investor Relations and Information Requests
Copies of Parker Drilling Company's Annual Report, its Annual Report on Form 10-K and Quarterly Reports on Form 10-Q to the Securities and Exchange Commission, and quarterly earnings releases are available on www.parkerdrilling.com or by contacting Investor Relations:

Richard Bajenski
Director, Investor Relations
Parker Drilling Company
5 Greenway Plaza, Suite 100
Houston, Texas 77046
Telephone: (281) 406-2030
Email: richard.bajenski@parkerdrilling.com

Transfer Agent and Registrar
Stockholders should refer specific questions concerning stock certificates directly to the stock transfer agent and registrar, Wells Fargo Bank N.A., at the address and phone number shown below:

Wells Fargo Bank, N.A.
Shareowner Relations
P.O. Box 64854
St. Paul, MN 55164-0854
Toll free: (800) 468-9716
Phone: (651) 450-4064

Independent Auditors
KPMG LLP
811 Main Street, Suite 4400
Houston, Texas 77002

Stock Exchange Listing
Shares of Parker Drilling Company are listed and traded on the New York Stock Exchange. The trading symbol is PKD.

PKD
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PARKER DRILLING

5 Greenway Plaza, Suite 100 | Houston, Texas 77046 | TEL 281.406.2000 FAX 281.406.2001 | **www.parkerdrilling.com**