PATTERSON UTI ENERGY INC
Form 10-K
February 12, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x 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 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	75-2504748
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

450 Gears Road, Suite 500, Houston, Texas 77067

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code:

(281) 765-7100

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.01 Par Value	The Nasdaq Global Select Market

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 x or No ¨

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x or 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. x

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 definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	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 x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $5.0 billion, calculated by reference to the closing price of $34.94 for the common stock on the Nasdaq

Global Select Market on that date.

As of February 5, 2015, the registrant had outstanding 146,458,290 shares of common stock, $0.01 par value, its only class of common stock.

Documents incorporated by reference:

Portions of the registrant’s definitive proxy statement for the 2015 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Report”) and other public filings and press releases by us contain “forward-looking statements” within the meaning of the Securities Act of 1933, as amended (the “Securities Act”), the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and the Private Securities Litigation Reform Act of 1995, as amended. These “forward-looking statements” involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; revenue and cost expectations and backlog; financing of operations; oil and natural gas prices; source and sufficiency of funds required for building new equipment and additional acquisitions (if further opportunities arise); impact of inflation; demand for our services; competition; equipment availability; government regulation; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historical or current facts and often use words such as “anticipates,” “believes,” “budgeted,” “continue,” “could,” “estimates,” “expects,” “intends,” “may,” “plans,” “project,” “strategy,” or “will,” or the nega and other words and expressions of similar meaning. The forward-looking statements are based on certain assumptions and analyses we make in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Forward-looking statements may be made orally or in writing, including, but not limited to, Management’s Discussion and Analysis of Financial Condition and Results of Operations included in this Report and other sections of our filings with the United States Securities and Exchange Commission (the “SEC”) under the Exchange Act and the Securities Act.

Forward-looking statements are not guarantees of future performance and a variety of factors could cause actual results to differ materially from the anticipated or expected results expressed in or suggested by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, volatility in customer spending and in oil and natural gas prices that could adversely affect demand for our services and their associated effect on rates, utilization, margins and planned capital expenditures, global economic conditions, excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction, equipment specialization and new technologies, adverse industry conditions, adverse credit and equity market conditions, difficulty in building and deploying new equipment and integrating acquisitions, shortages, delays in delivery and interruptions in supply of equipment, supplies and materials, weather, loss of key customers, liabilities from operations for which we do not have and receive full indemnification or insurance, ability to effectively identify and enter new markets, governmental regulation, ability to realize backlog, ability to retain management and field personnel and other factors. Refer to “Risk Factors” contained in Item 1A of this Report for a more complete discussion of factors that might affect our performance and financial results. You are cautioned not to place undue reliance on any of our forward-looking statements. These forward-looking statements are intended to relay our expectations about the future, and speak only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, changes in internal estimates or otherwise, except as required by law.

PART I

Item 1. Business

Available Information

This Report, along with our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are available free of charge through our internet website (www.patenergy.com) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on our website is not part of this Report or other filings that we make with the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Overview

We own and operate in the United States one of the largest fleets of land-based drilling rigs and a large fleet of pressure pumping equipment. The Company was formed in 1978 and reincorporated in 1993 as a Delaware corporation. Patterson Energy, Inc. and UTI Energy Corp. merged in 2001 to form Patterson-UTI Energy, Inc. In 2008, the corporate headquarters was moved from Snyder, Texas to Houston, Texas.

Our contract drilling business operates in the continental United States, and western and northern Canada. As of December 31, 2014, we had a drilling fleet that consisted of 239 marketable land-based drilling rigs. A drilling rig includes the structure, power source and machinery necessary to cause a drill bit to penetrate the earth to a depth desired by the customer. A drilling rig is considered marketable at a point in time if it is operating or can be made ready to operate without significant capital expenditures. We also have a substantial inventory of drill pipe and drilling rig components that support our ongoing drilling operations.

We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian region. Pressure pumping services consist primarily of well stimulation services (such as hydraulic fracturing) and cementing services for completion of new wells and remedial work on existing wells. As of December 31, 2014, we had approximately 1.0 million hydraulic horsepower to provide these services. Our pressure pumping operations are supported by a fleet of other equipment, including blenders, tractors, manifold trailers and numerous trailers for transportation of materials to and from the worksite as well as bins for storage of materials at the worksite.

We also own and invest in oil and natural gas assets as a non-operating working interest owner. Our oil and natural gas working interests are located primarily in Texas and New Mexico.

Recent Developments

Oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $105.68 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $50 per barrel during the first week in February 2015 (WTI spot price as reported by the

United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing a severe downturn. Market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2015 will be a challenging year for our industry.

We believe the vast majority of exploration and production companies, including our customers, have significantly reduced their 2015 capital spending plans. The initial impact of these spending reductions is evidenced by the published rig counts which have declined more 25% since their recent peak in October 2014.

Our rig count has also declined. During October 2014, the number of our drilling rigs operating in the United States was as high as 214, and as of February 10, 2015 we had 173 drilling rigs operating in the United States. We have received indications of customers' intent to early terminate a number of term contracts and many of our drilling customers are seeking price reductions. We expect the number of our drilling rigs operating in the United States to decline at least another 20% during the next 90 days.

Our pressure pumping business is also beginning to see the effects of reduced spending by customers. Some previously scheduled pressure pumping jobs have been cancelled or deferred and many customers are also seeking price reductions.

In anticipation of this downturn, we began reducing our cost structure in the fourth quarter of 2014. In 2015, we have continued to reduce our cost structure and, to date, we have reduced our drilling headcount at a rate slightly higher than the reduction in our rig count. We have also reduced our capital expenditure plans for 2015. Along with other reductions, we now plan to only build new drilling rigs that are currently committed under term contracts. We plan to continue to adjust our cost structure in line with our level of operating activity.

We expect that our term contract coverage and scalability with respect to labor and other operating costs should position us to weather this downturn. In the event oil prices remain depressed for a sustained period, or decline further, however, we may experience further, significant declines on both drilling activity and spot dayrate pricing, and on pressure pumping activity and pricing, which could have a material adverse effect on our business, financial condition and results of operations.

Industry Segments

Our revenues, operating profits and identifiable assets are primarily attributable to three industry segments:

- contract drilling services,
- pressure pumping services, and
- oil and natural gas exploration and production.

All of our industry segments had operating profits in 2012 and 2013. In 2014, our contract drilling services and our pressure pumping services segments had operating profits and our oil and natural gas exploration and production segment had an operating loss. Our oil and natural gas assets constituted approximately 1% of our consolidated assets as of December 31, 2014.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 14 of Notes to Consolidated Financial Statements included as a part of Items 7 and 8, respectively, of this Report for financial information pertaining to these industry segments.

Contract Drilling Operations

General — We market our contract drilling services to major and independent oil and natural gas operators. As of December 31, 2014, we had 239 marketable land-based drilling rigs based in the following regions:

- 55 in west Texas and southeastern New Mexico,
- 23 in north central and east Texas, northern Louisiana and eastern Oklahoma,
- 37 in the Rocky Mountain region (Colorado, Utah, Wyoming, Montana and North Dakota),
- 40 in south Texas,
- 34 in the Texas panhandle and western Oklahoma,
- 40 in the Appalachian region (Pennsylvania, Ohio and West Virginia), and
- 10 in western and northern Canada.

Our marketable drilling rigs have rated maximum depth capabilities ranging from 10,000 feet to 25,000 feet. Of these drilling rigs, 195 are electric rigs and 44 are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the power from its diesel engines (the sole energy source for a mechanical rig) into electricity to power the rig. We also have a substantial inventory of drill pipe and drilling rig components, which may be used in the activation of additional drilling rigs or as replacement parts for marketable rigs.

Drilling rigs are typically equipped with engines, drawworks, masts, pumps to circulate the drilling fluid, blowout preventers, drill pipe and other related equipment. Over time, components on a drilling rig are replaced or rebuilt. We spend significant funds each year as part of a program to modify, upgrade and maintain our drilling rigs to ensure that our drilling equipment is competitive. We have spent over $2.0 billion during the last three years on capital expenditures to (1) build new land drilling rigs and (2) modify, upgrade and extend the lives of components of our drilling fleet. During fiscal years 2014, 2013 and 2012, we spent approximately $772 million, $505 million and $745 million, respectively, on these capital expenditures.

Depth and complexity of the well and drill site conditions are the principal factors in determining the specifications of the rig selected for a particular job.

Our contract drilling operations depend on the availability of drill pipe, drill bits, replacement parts and other related rig equipment, fuel and other materials and qualified personnel. Some of these have been in short supply from time to time.

Drilling Contracts — Most of our drilling contracts are with established customers on a competitive bid or negotiated basis. Our bid for each job depends upon location, equipment to be used, estimated risks involved, estimated duration of the job, availability of drilling rigs and other factors particular to each proposed contract. Our drilling contracts are either on a well-to-well basis or a term basis. Well-to-well contracts are generally short-term in nature and cover the drilling of a single well or a series of wells. Term contracts are entered into for a specified period of time (frequently six months to three years) and provide for the use of the drilling rig to drill multiple wells. During 2014, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 20 days.

Our drilling contracts obligate us to provide and operate a drilling rig and to pay certain operating expenses, including wages of our drilling personnel and necessary maintenance expenses. Most drilling contracts are subject to termination by the customer on short notice and may or may not contain provisions for an early termination payment to us in the event that the contract is terminated by the customer. We believe that our drilling contracts generally provide for indemnification rights and obligations that are customary for the markets in which we conduct those operations; however, each drilling contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer requirements or other factors.

Our drilling contracts provide for payment on a daywork basis. Under daywork contracts, we provide the drilling rig and crew to the customer. The customer supervises the drilling of the well. Our compensation is based on a contracted rate per day during the period the drilling rig is utilized. We often receive a lower rate when the drilling rig is moving or when drilling operations are interrupted or restricted by adverse weather conditions or other conditions beyond our control. Daywork contracts typically provide separately for mobilization of the drilling rig. All of the wells we drilled in 2014, 2013 and 2012 were under daywork contracts.

From time to time more than five years ago, we contracted to drill some wells to a certain depth under specified conditions for a fixed price per foot (on a footage basis) or for a fixed fee (on a turnkey basis). We generally assume greater operational and economic risk drilling on a turnkey basis than on a footage basis and greater operational and economic risk drilling on a footage basis than on a daywork basis.

Contract Drilling Activity — Information regarding our contract drilling activity for the last three years follows:

	Year Ended December 31,		
	2014	2013	2012
Average rigs operating per day(1)	211	192	221
Number of rigs operated during the year	231	235	267
Number of wells drilled during the year	3,740	3,378	3,587
Number of operating days	77,000	69,918	80,833

(1) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

Drilling Rigs and Related Equipment — We have made significant upgrades during the last several years to our drilling fleet to match the needs of our customers. While conventional wells remain an important source of oil and natural gas, our customers have expanded the development of shale and other unconventional wells to help supply the long-term demand for oil and natural gas in North America.

To address our customers' needs for drilling horizontal wells in shale and other unconventional resource plays, we have expanded our areas of operation and improved the capability of our drilling fleet. We have delivered new APEX® rigs to the market and have made performance and safety improvements to existing high capacity rigs. APEX 1500® rigs are 1,500 horsepower electric rigs with advanced electronic drilling systems, 500 ton top drives, iron roughnecks, hydraulic catwalks, and other highly automated pipe handling equipment. APEX 1000® rigs are 1,000 horsepower electric rigs with advanced technology equipment similar to the APEX 1500® rigs, but with a more compact design to fit on smaller locations. APEX WALKING® rigs are designed to efficiently drill multiple wells from a single pad, by "walking" between the wellbores without requiring time to lower the mast and lay down the drill pipe. Many APEX 1500® and APEX 1000® rigs have also been equipped with walking systems as noted below. As of December 31, 2014, our drilling fleet was comprised of the following:

	Number of Rigs			
Classification	U.S.	Canada	Total	With Walking Systems
APEX 1500 rigs	81	—	81	43
APEX 1000 rigs	15	—	15	9
APEX WALKING rigs	49	—	49	49
Other electric rigs	44	6	50	4
Total electric rigs	189	6	195	105
Mechanical rigs	40	4	44	—
Total	229	10	239	105

	Number of Rigs		
Horsepower	U.S.	Canada	Total
950 and less	13	5	18
1,000 to 1,400	81	5	86
1,500	122	—	122
1,700 and greater	13	—	13
Total	229	10	239
Average horsepower	1,327	1,025	1,314
Average depth rating	18,096	14,005	17,925

At December 31, 2014, we owned and operated 286 trucks and 323 trailers used to rig down, transport and rig up our drilling rigs.

We perform repair and/or overhaul work to our drilling rig equipment at our yard facilities located in Texas, Oklahoma, Wyoming, Colorado, North Dakota, Pennsylvania and western Canada.

Pressure Pumping Operations

General — We provide pressure pumping services to oil and natural gas operators primarily in Texas (Southwest Region) and the Appalachian region (Northeast Region). Pressure pumping services consist of well stimulation services (such as hydraulic fracturing) and cementing services for the completion of new wells and remedial work on existing wells. Wells drilled in shale formations and other unconventional plays require well stimulation through hydraulic fracturing to allow the flow of oil and natural gas. This is accomplished by pumping fluids under pressure into the well bore to fracture the formation. Many wells in conventional plays also receive well stimulation services. The cementing process inserts material between the wall of the well bore and the casing to support and stabilize the casing.

Pressure Pumping Contracts – Our pressure pumping operations are conducted pursuant to a work order for a specific job or pursuant to a term contract. The term contracts are generally entered into for a specified period of time and may include minimum revenue, usage or stage requirements. We are compensated based on a combination of charges for equipment, personnel, materials, mobilization and other items. We believe that our pressure pumping contracts generally provide for indemnification rights and obligations that are customary for the markets in which we conduct those operations; however, each pressure pumping contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer requirements or other factors.

Equipment — We have pressure pumping equipment used in providing hydraulic and nitrogen fracturing services as well as nitrogen, cementing and acid pumping services, with a total of approximately 1.0 million hydraulic horsepower as of December 31, 2014. Pressure pumping equipment at December 31, 2014 included:

	Hydraulic Fracturing Equipment	Other Pumping Equipment	Total
Southwest Region:			
Number of units	275	32	307
Approximate hydraulic horsepower	638,800	32,165	670,965
Northeast Region:			
Number of units	149	94	243
Approximate hydraulic horsepower	303,800	54,700	358,500
Combined:			
Number of units	424	126	550
Approximate hydraulic horsepower	942,600	86,865	1,029,465

Our pressure pumping operations are supported by a fleet of other equipment including blenders, tractors, manifold trailers and numerous trailers for transportation of materials to and from the worksite as well as bins for storage of materials at the worksite.

Materials – Our pressure pumping operations require the use of acids, chemicals, proppants, fluid supplies and other materials, any of which can be in short supply, including severe shortages, from time to time. We purchase these materials from various suppliers. These purchases are made in the spot market or pursuant to other arrangements that do not cover all of our required supply and that sometimes require us to purchase the supply or pay liquidated damages if we do not purchase the material. Given the limited number of suppliers of certain of our materials, we may not always be able to make alternative arrangements if we are unable to reach an agreement with a supplier for delivery of any particular material or should one of our suppliers fail to timely deliver our materials.

Oil and Natural Gas Interests

We own and invest in oil and natural gas assets as a non-operating working interest owner. Our oil and natural gas working interests are located primarily in producing regions of Texas and New Mexico. Our oil and natural gas assets constituted approximately 1% of our consolidated assets as of December 31, 2014.

Customers

The customers of each of our contract drilling and pressure pumping business segments are oil and natural gas operators. Our customer base includes both major and independent oil and natural gas operators. With respect to our consolidated operating revenues in 2014, we received approximately 41% from our ten largest customers, 28% from our five largest customers and 16% from our two largest customers. The loss of, or reduction in business from, one or more of our larger customers could have a material adverse effect on our business, financial condition, cash flows and results of operations. During 2014, no single customer accounted for more than 10% of our consolidated operating revenues.

Competition

The contract drilling and pressure pumping businesses are highly competitive. Historically, available equipment used in these businesses has frequently exceeded demand. The price for our services is a key competitive factor, in part because equipment used in our businesses can be moved from one area to another in response to market conditions. In addition to price, we believe availability, condition and technical specifications of equipment, quality of personnel, service quality and safety record are key factors in determining which contractor is awarded a job. We expect that the market for land drilling and pressure pumping services will continue to be highly competitive.

Government and Environmental Regulation

All of our operations and facilities are subject to numerous federal, state, foreign, regional and local laws, rules and regulations related to various aspects of our business, including:

- drilling of oil and natural gas wells,

- hydraulic fracturing, cementing, nitrogen and acidizing and related well servicing activities,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks and injection wells, and
- our employees.

To date, applicable environmental laws and regulations in the places in which we operate have not required the expenditure of significant resources outside the ordinary course of business. We do not anticipate any material capital expenditures for environmental control facilities or extraordinary expenditures to comply with environmental rules and regulations in the foreseeable future. However, compliance costs under existing laws or under any new requirements could become material, and we could incur liability in any instance of noncompliance.

Our business is generally affected by political developments and by federal, state, foreign, regional and local laws, rules and regulations that relate to the oil and natural gas industry. The adoption of laws, rules and regulations affecting the oil and natural gas industry for economic, environmental and other policy reasons could increase costs relating to drilling, completion and production, and otherwise have an adverse effect on our operations. Federal, state, foreign, regional and local environmental laws, rules and regulations currently apply to our operations and may become more stringent in the future. Any suspension or moratorium of the services we or others provide, whether or not short-term in nature, by a federal, state, foreign, regional or local governmental authority, could have a material adverse effect on our business, financial condition and results of operation.

We believe we use operating and disposal practices that are standard in the industry. However, hydrocarbons and other materials may have been disposed of, or released in or under properties currently or formerly owned or operated by us or our predecessors, which may have resulted, or may result, in soil and groundwater contamination in certain locations. Any contamination found on, under or originating from the properties may be subject to remediation requirements under federal, state, foreign, regional and local laws, rules and regulations. In addition, some of these properties have been operated by third parties over whom we have no control of their treatment of hydrocarbon and other materials or the manner in which they may have disposed of or released such materials. We could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, it is possible we could be held responsible for oil and natural gas properties in which we own an interest but are not the operator.

Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

In the United States, the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, commonly known as CERCLA, and comparable state statutes impose strict liability on:

- owners and operators of sites, including prior owners and operators who are no longer active at a site; and
- persons who disposed of or arranged for the disposal of “hazardous substances” found at sites.

The Federal Resource Conservation and Recovery Act (“RCRA”), as amended, and comparable state statutes and implementing regulations govern the disposal of “hazardous wastes.” Although CERCLA currently excludes petroleum from the definition of “hazardous substances,” and RCRA also excludes certain classes of exploration and production wastes from regulation, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

The Federal Water Pollution Control Act and the Oil Pollution Act of 1990, as amended, and implementing regulations govern:

- the prevention of discharges, including oil and produced water spills, into jurisdictional waters; and
- liability for drainage into such waters.

The Oil Pollution Act imposes strict liability for a comprehensive and expansive list of damages from an oil spill into jurisdictional waters from facilities. Liability may be imposed for oil removal costs and a variety of public and private damages. Penalties may also be imposed for violation of federal safety, construction and operating regulations, and for failure to report a spill or to cooperate fully in a clean-up.

The Oil Pollution Act also expands the authority and capability of the federal government to direct and manage oil spill clean-up and operations, and requires operators to prepare oil spill response plans in cases where it can reasonably be expected that substantial harm will be done to the environment by discharges on or into navigable waters. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party, such as us, to civil or criminal actions. Although the liability for owners and operators is the same under the Federal Water Pollution Act, the damages recoverable under the Oil Pollution Act are potentially much greater and can include natural resource damages.

The U.S. Occupational Safety and Health Administration ("OSHA") promulgates and enforces laws and regulations governing the protection of the health and safety of employees. The OSHA hazard communication standard, U.S. Environmental Protection Agency ("EPA") community right-to-know regulations under Title III of CERCLA and similar state statutes require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governments and citizens. Also, OSHA has established a variety of standards related to workplace exposure to hazardous substances and employee health and safety.

Our activities include the performance of hydraulic fracturing services to enhance the production of oil and natural gas from formations with low permeability, such as shale and other unconventional formations. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some state and local jurisdictions have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities, which in turn could have an adverse effect on the hydraulic fracturing services that we render for our exploration and production customers. See "Item 1A. Risk Factors – Potential Legislation and Regulation Covering Hydraulic Fracturing Could Increase Our Costs and Limit or Delay Our Operations."

In Canada, a variety of federal, provincial and municipal laws, rules and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances to the environment. Other jurisdictions where we may conduct operations have similar environmental and regulatory regimes with which we would be required to comply. These laws, rules and regulations also require that facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, new projects or changes to existing projects may require the submission and approval of environmental assessments or permit applications. These laws, rules and regulations are subject to frequent change, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment.

Our operations are also subject to federal, state, foreign, regional and local laws, rules and regulations for the control of air emissions, including those associated with the Federal Clean Air Act and the Canadian Environmental Protection Act. We and our customers may be required to make capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For more information, please refer to our discussion under "Item 1A. Risk Factors – Environmental and Occupational Health and Safety Laws and Regulations, Including Violations Thereof, Could Materially Adversely Affect Our Operating Results."

We are aware of the increasing focus of local, state, national and international regulatory bodies on greenhouse gas ("GHG") emissions and climate change issues. We are also aware of legislation proposed by United States lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by the EPA and the Canadian provinces of Alberta and British Columbia. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition. See “Item 1A. Risk Factors – Legislation and Regulation of Greenhouse Gases Could Adversely Affect Our Business.”

Risks and Insurance

Our operations are subject to many hazards inherent in the contract drilling and pressure pumping businesses, including inclement weather, blowouts, well fires, loss of well control, pollution and reservoir damage. These hazards could cause personal injury or death, work stoppage, and serious damage to equipment and other property, as well as significant environmental and reservoir damages. These risks could expose us to substantial liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages.

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our drilling and pressure pumping contracts typically contain provisions requiring our customer to indemnify us for, among other things, reservoir and certain pollution damage. Our right to indemnification may, however, be unenforceable or limited due to negligent or willful acts or omissions by us, our subcontractors and/or suppliers. Our customers may dispute, or be unable to meet, their indemnification obligations to us due to financial, legal or other reasons. Accordingly, we may be unable to transfer these risks to our customers by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we are not fully insured against all risks, either because insurance is not available or because of the high premium costs. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our rigs and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, our drilling rigs and certain other assets, such insurance does not cover the full replacement cost of the rigs or other assets. We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we generally maintain a $1.5 million per occurrence deductible on our workers' compensation and equipment insurance coverage and a $2.0 million per occurrence self-insured retention on our general liability coverage and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We self-insure a number of other risks, including loss of earnings and business interruption, and do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance will not in all situations provide sufficient funds to protect us from all liabilities that could result from our operations. Our coverage includes aggregate policy limits and exclusions. As a result, we retain the risk for any loss in excess of these limits or that is otherwise excluded from our coverage. There can be no assurance that insurance will be available to cover any or all of our operational risks, or, even if available, that insurance premiums or other costs will not rise significantly in the future, so as to make the cost of such insurance prohibitive or that our coverage will cover a specific loss. Further, we may experience difficulties in collecting from insurers or such insurers may deny all or a portion of our claims for insurance coverage.

If a significant accident or other event occurs and is not fully covered by insurance or an enforceable or recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations. See "Item 1A. Risk Factors – Our Operations Are Subject to a Number of Operational Risks, Including Environmental and Weather Risks, Which Could Expose Us to Significant Losses and Damage Claims. We Are Not Fully Insured Against All of These Risks and Our Contractual Indemnity Provisions May Not Fully Protect Us."

Employees

We had approximately 7,900 full-time employees as of February 10, 2015. The number of employees fluctuates depending on the current and expected demand for our services. We consider our employee relations to be satisfactory. None of our employees are represented by a union.

Seasonality

Seasonality has not significantly affected our overall operations. However, our drilling operations in Canada are subject to slow periods of activity during the annual spring thaw. Additionally, toward the end of some years, we experience slower activity in our pressure pumping operations in connection with the holidays and as customers' capital expenditure budgets are depleted. Occasionally, our operations have been negatively impacted by severe weather conditions.

Raw Materials and Subcontractors

We use many suppliers of raw materials and services. Although these materials and services have historically been available, there is no assurance that such materials and services will continue to be available on favorable terms or at all. We also utilize numerous independent subcontractors from various trades.

Item 1A. Risk Factors.

You should consider each of the following factors as well as the other information in this Report in evaluating our business and our prospects. Additional risks and uncertainties not presently known to us or that we currently consider immaterial may also impair our business operations. If any of the following risks actually occur, our business, financial condition, cash flows and results of operations could be harmed. You should also refer to the other information set forth in this Report, including our consolidated financial statements and the related notes.

We Are Dependent on the Oil and Natural Gas Industry and Market Prices for Oil and Natural Gas. Declines in Customers' Operating and Capital Expenditures and in Oil and Natural Gas Prices May Adversely Affect Our Operating Results.

We depend on our customers' willingness to make operating and capital expenditures to explore for, develop and produce oil and natural gas in North America. If these expenditures decline, our business may suffer. Our customers' willingness to explore, develop and produce depends largely upon prevailing industry conditions that are influenced by numerous factors over which we have no control, such as:

- the supply of and demand for oil and natural gas, including current natural gas storage capacity and usage,
- the prices, and expectations about future prices, of oil and natural gas,
- the supply of and demand for drilling and pressure pumping equipment,
- the cost of exploring for, developing, producing and delivering oil and natural gas,
- the environmental, tax and other laws and governmental regulations regarding the exploration, development, production and delivery of oil and natural gas, and in particular, public pressure on, and legislative and regulatory interest within, federal, state, foreign, regional and local governments to stop, significantly limit or regulate drilling and pressure pumping activities, including hydraulic fracturing, and
- merger and divestiture activity among oil and natural gas producers.

In particular, our revenue, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by factors such as:

- market supply and demand,
- domestic and international military, political, economic and weather conditions,
- the desire and ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,
- technical advances affecting energy consumption and production, and
- the price and availability of alternative fuels.

All of these factors are beyond our control. During the nine months ended September 30, 2014, oil prices averaged $99.96 per barrel, natural gas prices averaged $4.59 per Mcf and demand for drilling activities increased. During the three months ended December 31, 2014, drilling activity slowed as oil prices averaged $73.16 per barrel and natural gas prices averaged $3.80 per Mcf. Drilling activity has significantly decreased since December 31, 2014, as oil prices averaged $47.22 per barrel and natural gas prices averaged $2.99 per Mcf during January 2015. Our average number of rigs operating remains well below the number of our available rigs, and given current oil pricing and existing market trends, we expect our average number of rigs operating to continue to decline through at least the first quarter of 2015.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Continued low market prices for oil and natural gas will likely result in decreased demand for our drilling rigs and pressure pumping services and adversely affect our operating results, financial condition and cash flows. Even during periods of high prices for oil and natural gas, companies exploring for oil and natural gas may cancel or curtail programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons, which could reduce demand for our drilling rigs and pressure pumping services.

Global Economic Conditions May Adversely Affect Our Operating Results.

Global economic conditions and volatility in commodity prices may cause our customers to reduce or curtail their drilling and well completion programs, which could result in a decrease in demand for our services. In addition, uncertainty in the capital markets, whether due to global economic conditions, low commodity prices or otherwise may result in reduced access to financing by us, our customers and our suppliers and reduced demand for our services. Furthermore, these factors may result in certain of our customers experiencing an inability to pay suppliers, including us. The global economic environment in the past has experienced significant deterioration in a relatively short period, and there is no assurance that the global economic environment will not quickly deteriorate again due to one or more factors, including a decline in the price for oil or natural gas. A deterioration in the global economic environment could have a material adverse effect on our business, financial condition, cash flows and results of operations.

A General Excess of Operable Land Drilling Rigs, Increasing Rig Specialization and Excess Pressure Pumping Equipment May Adversely Affect Our Utilization and Profit Margins.

The North American oil and natural gas services industry has experienced downturns in demand during the last decade, including a downturn that started late in 2014. During these periods, there have been substantially more drilling rigs and pressure pumping equipment available than necessary to meet demand. As a result, drilling and pressure pumping contractors have had difficulty sustaining profit margins and, at times, have incurred losses during the downturn periods.

Construction of new technology drilling rigs has increased in recent years. The addition of new technology drilling rigs to the market, combined with a reduction in the drilling of vertical wells, has resulted in excess capacity of conventional drilling rigs. Similarly, the substantial recent increase in unconventional resource plays has led to higher demand for pressure pumping services and there has been a significant increase in the construction of new pressure pumping equipment across the industry. As a result of low oil and natural gas prices and the construction of new equipment, there is currently an excess of drilling rigs and pressure pumping equipment available. In circumstances of excess capacity, providers of contract drilling and pressure pumping services have difficulty sustaining profit margins and may sustain losses during downturn periods. We cannot predict the future level of demand for our contract drilling or pressure pumping services or future conditions in the oil and natural gas contract drilling or pressure pumping businesses.

In addition, unconventional resource plays have substantially increased and some drilling rigs are not capable of drilling these wells efficiently. Accordingly, the utilization of some older technology drilling rigs may be hampered by their lack of capability to successfully compete for this work. Other ongoing factors which could continue to adversely affect utilization rates and pricing, even in an environment of high oil and natural gas prices and increased drilling activity, include:

- movement of drilling rigs from region to region,
- reactivation of land-based drilling rigs, and
- construction of new technology drilling rigs.

Shortages, Delays in Delivery and Interruptions in Supply of Drill Pipe, Replacement Parts, Other Equipment, Supplies and Materials Adversely Affect Our Operating Results.

During periods of increased demand for drilling and pressure pumping services, the industry has experienced shortages of drill pipe, replacement parts, other equipment, supplies and materials, including, in the case of our pressure pumping operations, proppants, acid, gel and water. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. In addition, any interruption in supply could result in significant delays in delivery of equipment and materials or prevent operations. Interruptions may be caused by, among other reasons:

- weather issues, whether short-term such as a hurricane, or long-term such as a drought,
- transportation and other logistical challenges, and
- a shortage in the number of vendors able or willing to provide the necessary equipment, supplies and materials, including as a result of commitments of vendors to other customers or third parties.

These price increases, delays in delivery and interruptions in supply may require us to increase capital and repair expenditures and incur higher operating costs. Severe shortages, delays in delivery and interruptions in supply could limit our ability to construct and operate our drilling rigs and pressure pumping equipment and could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our Operations Are Subject to a Number of Operational Risks, Including Environmental and Weather Risks, Which Could Expose Us to Significant Losses and Damage Claims. We Are Not Fully Insured Against All of These Risks and Our Contractual Indemnity Provisions May Not Fully Protect Us.

Our operations are subject to many hazards inherent in the contract drilling and pressure pumping businesses, including inclement weather, blowouts, well fires, loss of well control, pollution, exposure and reservoir damage. These hazards could cause personal injury or death, work stoppage, and serious damage to equipment and other property, as well as significant environmental and reservoir damages. These risks could expose us to substantial liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages.

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our drilling and pressure pumping contracts typically contain provisions requiring our customers to indemnify us for, among other things, reservoir and certain pollution damage. Our right to indemnification may, however, be unenforceable or limited due to negligent or willful acts or omissions by us, our subcontractors and/or suppliers. Our customers and other third parties may dispute, or be unable to meet, their indemnification obligations to us due to financial, legal or other reasons. Accordingly, we may be unable to transfer these risks to our customers and other third parties by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we are not fully insured against all risks, either because insurance is not available or because of the high premium costs. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our rigs and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, our drilling rigs and certain other assets, such insurance does not cover the full replacement cost of the rigs or other assets. We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we generally maintain a $1.5 million per occurrence deductible on our workers' compensation and equipment insurance coverage and a $2.0 million per occurrence self-insured retention on our general liability coverage and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We self-insure a number of other risks, including loss of earnings and business interruption, and do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance will not in all situations provide sufficient funds to protect us from all liabilities that could result from our operations. Our coverage includes aggregate policy limits and exclusions. As a result, we retain the risk for any loss in excess of these limits or that is otherwise excluded from our coverage. There can be no assurance that insurance will be available to cover any or all of our operational risks, or, even if available, that insurance premiums or other costs will not rise significantly in the future, so as to make the cost of such insurance prohibitive or that our coverage will cover a specific loss. Further, we may experience difficulties in collecting from insurers or such insurers may deny all or a portion of our claims for insurance coverage. Incurring a liability for which we are not fully insured or indemnified could materially adversely affect our business, financial condition, cash flows and results of operations.

If a significant accident or other event occurs and is not fully covered by insurance or an enforceable or recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

New Technologies May Cause Our Operating Methods and Equipment to Become Less Competitive, and Higher Levels of Capital Expenditures May Be Necessary to Remain Competitive in our Industry.

The market for our services is characterized by continual technological and process developments that have resulted in, and will likely continue to result in, substantial improvements in the functionality and performance of rigs and equipment. Our customers are increasingly demanding the services of newer, higher specification drilling rigs. Accordingly, a higher level of capital expenditures may be required to maintain and improve existing rigs and equipment and purchase and construct newer, higher specification drilling rigs to meet the increasingly sophisticated needs of our customers. In addition, technological changes, process improvements and other factors that increase operational efficiencies could result in oil and natural gas wells being drilled and completed more quickly, which could reduce the number of revenue earning days. Technological and process developments in the pressure pumping business could have similar effects.

In recent years, we have added drilling rigs to our fleet through new construction, and we have purchased new pressure pumping equipment. Although we take measures to ensure that we use advanced oil and natural gas drilling technology, changes in technology or improvements in competitors' equipment could make our equipment less competitive.

If we are not successful in building new rigs and pressure pumping equipment or upgrading our existing rigs and pressure pumping equipment in a timely and cost-effective manner, we could lose market share. One or more technologies that we implement in the future may not work as we expect, and we may be adversely affected. Additionally, new technologies, services or standards could render some of our services, drilling rigs or pressure pumping equipment obsolete, which could have a material adverse impact on our business, financial condition, cash flows and results of operation.

Our Current Backlog of Contract Drilling Revenue May Not Ultimately Be Realized as Fixed-Term Contracts May in Certain Instances Be Terminated Without an Early Termination Payment.

As of December 31, 2014, our contract drilling backlog for future revenues under term contracts, which we define as contracts with a fixed term of six months or more, was approximately $1.5 billion. Fixed-term drilling contracts customarily provide for termination at the election of the customer, with an early termination payment to us if a contract is terminated prior to the expiration of the fixed term. However, in certain circumstances, for example, destruction of a drilling rig that is not replaced within a specified period of time, our bankruptcy, or a breach of our contract obligations, the customer may not be obligated to make an early termination payment to us. Additionally, during depressed market conditions or otherwise, customers may be unable to satisfy their contractual obligations or may seek to terminate, renegotiate or fail to honor their contractual obligations. In addition, we may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or negotiate our contracts for various reasons, including those described above. As a result, we may be unable to realize all of our current contract drilling backlog. In addition, the renegotiation or termination of fixed-term contracts without the receipt of early termination payments could have a material adverse effect on our business, financial condition, cash flows and results of operations.

The Oil Service Business Sectors in Which We Operate Are Highly Competitive with Excess Capacity, which Adversely Affects Our Operating Results.

The land drilling and pressure pumping businesses are highly competitive. At times, particularly in low commodity price environments, available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. This excess capacity has resulted in substantial competition for drilling and pressure pumping contracts. The ability to move drilling rigs and pressure pumping equipment from one market to another in response to market conditions heightens the competition in the industry.

We believe that price competition for drilling and pressure pumping contracts will continue to be intense due to the existence of available rigs and pressure pumping equipment. As a result of competition, our utilization may decrease and/or we may be unable to maintain or increase prices for our services, which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Reliance on Management and Competition for Experienced Personnel May Negatively Impact Our Financial Condition and Results of Operations

We greatly depend on the efforts of our key employees to manage our operations. The loss of members of management could have a material adverse effect on our business. In addition, we utilize highly skilled personnel in operating and supporting our businesses. In times of increasing demand for our services, it may be difficult to attract and retain qualified personnel. During periods of high demand for our services, wage rates for operations personnel are also likely to increase, resulting in higher operating costs. The loss of key employees, the failure to obtain or attract and retain qualified personnel and increased wage rates could have a material adverse effect on our business, financial condition, cash flows and results of operations.

The Loss of Large Customers Could Have a Material Adverse Effect on Our Financial Condition and Results of Operations.

With respect to our consolidated operating revenues in 2014, we received approximately 41% from our ten largest customers, 28% from our five largest customers and 16% from our two largest customers. The loss of, or reduction in business from, one or more of our larger customers could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Growth Through the Building of New Rigs and Pressure Pumping Equipment and Rig and Other Acquisitions Are Not Assured.

We have increased our drilling rig fleet and pressure pumping horsepower in the past through mergers, acquisitions and new construction. There can be no assurance that acquisition opportunities will be available in the future or that we will be able to execute timely or efficiently any plans for building new rigs and pressure pumping equipment. We are also likely to continue to face intense competition from other companies for available acquisition opportunities. In addition, because improved technology has enhanced the ability to recover oil and natural gas, contract drillers may continue to build new, high technology rigs and providers of pressure pumping services may continue to build new, high horsepower equipment.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions or build new rigs or pressure pumping equipment,
- successfully integrate additional drilling rigs, pressure pumping equipment or other assets or businesses,
- effectively manage the growth and increased size of our organization, drilling fleet and pressure pumping equipment,
- successfully deploy idle, stacked or additional rigs and pressure pumping equipment,
- maintain the crews necessary to operate additional drilling rigs and pressure pumping equipment, or
- successfully improve our financial condition, results of operations, business or prospects as a result of any completed acquisition or the building of new drilling rigs and pressure pumping equipment.

We may incur substantial indebtedness to finance future acquisitions, build new drilling rigs or build new pressure pumping equipment and also may issue equity, convertible or debt securities in connection with any such acquisitions or building program. Debt service requirements could represent a significant burden on our results of operations and financial condition, and the issuance of additional equity or convertible securities could be dilutive to existing stockholders. Also, continued growth could strain our management, operations, employees and other resources.

Environmental and Occupational Health and Safety Laws and Regulations, Including Violations Thereof Could Materially Adversely Affect Our Operating Results.

Our business is subject to numerous federal, state, foreign, regional and local laws, rules and regulations governing the discharge of substances into the environment, protection of the environment and worker health and safety, including, without limitation, laws concerning the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground storage tanks, and the use of underground injection wells. The cost of compliance with these laws and regulations could be substantial. A failure to comply with these requirements could expose us to:

- substantial civil, criminal and/or administrative penalties,
- modification, denial or revocation of permits or other authorizations,
- imposition of limitations on our operations, and
- performance of site investigatory, remedial or other corrective actions.

In addition, environmental laws and regulations in the countries in which we operate impose a variety of requirements on “responsible parties” related to the prevention of spills and liability for damages from such spills. As an owner and operator of land-based drilling rigs and pressure pumping equipment, we may be deemed to be a responsible party under these laws and regulations.

Changes in environmental laws and regulations occur frequently and such laws and regulations tend to become more stringent over time. Stricter laws, regulations or enforcement policies could significantly increase compliance costs for us and our customers and have a material adverse effect on our operations or financial position. For example, on August 16, 2012, the EPA issued final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and National Emissions Standards for Hazardous Air Pollutants (“NESHAPS”) to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells are now required to use completion combustion device equipment (i.e., flaring) if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include Maximum Achievable Control Technology standards for “small” glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. These rules may require the implementation of new operating standards which may impact our business. In 2012, seven states sued the EPA to compel the agency to make a determination as to whether setting standards of performance limiting methane emissions from oil and natural gas sources is appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and natural gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry. In January 2015, EPA announced plans to issue a proposed rule in summer 2015 governing methane emissions from the oil and natural gas industry. If these or other initiatives result in an increase in regulation, it could increase costs to us and our customers or reduce demand for our services, which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Potential Legislation and Regulation Covering Hydraulic Fracturing Could Increase Our Costs and Limit or Delay Our Operations.

Members of the U.S. Congress and the EPA are reviewing proposals for more stringent regulation of hydraulic fracturing, a technology employed by our pressure pumping business, which involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. For example, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. As part of this study, the EPA sent requests to a number of companies, including our company, for information on their hydraulic fracturing practices. We have responded to the inquiry. The EPA released a progress report on December 21, 2012 outlining work currently underway and is expected to release a draft final report in early 2015. This and other ongoing or proposed studies, depending on their course, and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act (“SDWA”) or other regulatory mechanism. In addition, legislation has been proposed in the U.S. Congress to amend the SDWA to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing ground water or causing other damage. These bills, if adopted, could establish an additional level of regulation at the federal or state level that could limit or delay operational activities or increase operating costs and could result in additional regulatory burdens that could make it more difficult to perform or limit hydraulic fracturing and increase our costs of compliance and doing business.

Regulatory efforts at the federal level and in many states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. The EPA has asserted federal regulatory authority over hydraulic fracturing using fluids that contain “diesel fuel” under the SWDA Underground Injection Control Program and has released a revised guidance regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. In May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking, seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. These regulatory initiatives could each spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities. Certain states where we operate have adopted or are considering disclosure legislation and/or regulations. For example, Colorado, North Dakota, Montana, Texas, Louisiana, and Wyoming have adopted a variety of well construction, set back and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. Additional regulation could increase the costs of conducting our business and could materially reduce our business opportunities and revenues if our customers decrease their levels of activity in response to such regulation.

Finally, some jurisdictions have taken steps to enact hydraulic fracturing bans or moratoria. New York announced in December 2014 that it will ban high volume fracturing activities combined with horizontal drilling. Certain communities in Colorado have also enacted bans on hydraulic fracturing. Voters in the city of Denton, Texas also recently approved a moratorium on hydraulic fracturing. These actions have been the subject of legal challenges.

The adoption of any future federal, state, foreign, regional or local laws that impact permitting requirements for, result in reporting obligations on, or otherwise limit or ban, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing and could increase our costs of compliance and doing business and reduce demand for our services. Regulation that significantly restricts or prohibits hydraulic fracturing could have a material adverse impact on our business, financial condition, cash flows and results of operations.

Legislation and Regulation of Greenhouse Gases Could Adversely Affect Our Business

We are aware of the increasing focus of local, state, regional, national and international regulatory bodies on GHG emissions and climate change issues. Legislation to regulate GHG emissions has periodically been introduced in the U.S. Congress, and there has been a wide-ranging policy debate, both in the United States and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries to meet stringent new standards that would require substantial reductions in carbon emissions. Those reductions could be costly and difficult to implement. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources on an annual basis. Further, following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA finalized a rule to address permitting of GHG emissions from stationary sources under the Clean Air Act’s New Source Review Prevention of Significant Deterioration (“PSD”) and Title V programs. This final rule “tailors” the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Several states and geographic regions in the United States have also adopted legislation and regulations to reduce emissions of GHGs. Additional legislation or regulation by these states and regions, the EPA, and/or any international agreements to which the United States may become a party, that control or limit GHG emissions or otherwise seek to address climate change could adversely affect our operations. The cost of complying with any new law, regulation or treaty will depend on the details of the particular program. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition. Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws or regulations 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 or regulations reduce demand for oil and natural gas.

Legal Proceedings Could Have a Negative Impact on our Business.

The nature of our business makes us susceptible to legal proceedings and governmental investigations from time to time. Lawsuits or claims against us could have a material adverse effect on our business, financial condition and results of operations. Any legal proceedings or claims, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

Political, Economic and Social Instability Risk and Laws Associated with Conducting International Operations Could Adversely Affect our Opportunities and Future Business.

We currently conduct operations in Canada, and we have incurred selling, general and administrative expenses related to the evaluation of and preparation for other international opportunities. International operations are subject to certain political, economic and other uncertainties generally not encountered in U.S. operations, including increased risks of social and political unrest, strikes, terrorism, war, kidnapping of employees, nationalization, forced negotiation or modification of contracts, difficulty resolving disputes and enforcing contractual rights, expropriation of equipment as well as expropriation of oil and gas exploration and drilling rights, changes in taxation policies, foreign exchange restrictions and restrictions on repatriation of income and capital, currency rate fluctuations, increased governmental ownership and regulation of the economy and industry in the markets in which we may operate, economic and financial instability of national oil companies, and restrictive governmental regulation, bureaucratic delays and general hazards associated with foreign sovereignty over certain areas in which operations are conducted.

There can be no assurance that there will not be changes in local laws, regulations and administrative requirements or the interpretation thereof which could have a material adverse effect on the cost of entry into international markets, the profitability of international operations or the ability to continue those operations in certain areas. Because of the impact of local laws, any future international operations in certain areas may be conducted through entities in which local citizens own interests and through entities (including joint ventures) in which we hold only a minority interest or pursuant to arrangements under which we conduct operations under contract to local entities. While we believe that neither operating through such entities nor pursuant to such arrangements would have a material adverse effect on our operations or revenues, there can be no assurance that we will in all cases be able to structure or restructure our operations to conform to local law (or the administration thereof) on terms we find acceptable.

There can be no assurance that we will:

- identify attractive opportunities in international markets,
- have sufficient capital resources to pursue and consummate international opportunities,
- successfully integrate international drilling rigs, pressure pumping equipment or other assets or businesses,
- effectively manage the start-up, development and growth of an international organization and assets,
- hire, attract and retain the personnel necessary to successfully conduct international operations, or
- successfully improve our financial condition, results of operations, business or prospects as a result of the entry into one or more international markets.

In addition, the U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. Some of the parts of the world where contract drilling and pressure pumping activities are conducted have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practice and could impact business. Any failure to comply with the FCPA or other anti-bribery legislation could subject to us to civil, criminal and/or administrative penalties or other sanctions, which could have a material adverse impact on our business, financial condition and results of operation. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of drilling rigs, pressure pumping equipment or other assets.

We may incur substantial indebtedness to finance an international transaction or operations and also may issue equity, convertible or debt securities in connection with any such transactions or operations. Debt service requirements could represent a significant burden on our results of operations and financial condition, and the issuance of additional equity or convertible securities could be dilutive to existing stockholders. Also, international expansion could strain our management, operations, employees and other resources.

The occurrence of one or more events arising from the types of risks described above could have a material adverse impact on our business, financial condition and results of operation.

Our Business Is Subject to Cybersecurity Risks and Threats.

Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. It is possible that our business, financial and other systems could be compromised, which might not be noticed for some period of time. Risks associated with these threats include, among other things, loss of intellectual property, disruption of our and customers' business operations and safety procedures, loss or damage to our worksite data delivery systems, unauthorized disclosure of personal information, and increased costs to prevent, respond to or mitigate cybersecurity events.

We Are Dependent Upon Our Subsidiaries to Meet our Obligations Under Our Long Term Debt

We have borrowings outstanding under our senior notes, term loan facility and, from time to time, revolving credit facility. These obligations are guaranteed by each of our existing U.S. subsidiaries other than immaterial subsidiaries. Our ability to meet our interest and principal payment obligations depends in large part on dividends paid to us by our subsidiaries. If our subsidiaries do not generate sufficient cash flows to pay us dividends, we may be unable to meet our interest and principal payment obligations.

Variable Rate Indebtedness Subjects Us to Interest Rate Risk, Which Could Cause Our Debt Service Obligations to Increase Significantly.

We have in place a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility. Interest is paid on the outstanding principal amount of borrowings under the credit facility at a floating rate based on, at our election, LIBOR or a base rate. The margin on LIBOR loans ranges from 2.25% to 3.25% and the margin on base rate loans ranges from 1.25% to 2.25%, based on our debt to capitalization ratio. At December 31, 2014, the margin on LIBOR loans was 2.25% and the margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at December 31, 2014, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2015. As of December 31, 2014, we had $303 million outstanding under our revolving credit facility at a weighted average interest rate of 2.65% and $82.5 million outstanding under our term credit facility at an interest rate of 2.50%. A one percent increase in the interest rate on the borrowings outstanding under our revolving credit facility and term credit facility as of December 31, 2014 would increase our annual cash interest expense by approximately $3.8 million. Interest rates could rise for various reasons in the future and increase our total interest expense, depending upon the amounts borrowed.

Anti-takeover Measures in Our Charter Documents and Under State Law Could Discourage an Acquisition and Thereby Affect the Related Purchase Price.

We are a Delaware corporation subject to the Delaware General Corporation Law, including Section 203, an anti-takeover law. Our restated certificate of incorporation authorizes our Board of Directors to issue up to one million shares of preferred stock and to determine the price, rights (including voting rights), conversion ratios, preferences and privileges of that stock without further vote or action by the holders of the common stock. It also prohibits stockholders from acting by written consent without the holding of a meeting. In addition, our bylaws impose certain advance notification requirements as to business that can be brought by a stockholder before annual stockholder meetings and as to persons nominated as directors by a stockholder. As a result of these measures and others, potential acquirers might find it more difficult or be discouraged from attempting to effect an acquisition transaction with us. This may deprive holders of our securities of certain opportunities to sell or otherwise dispose of the securities at above-market prices pursuant to any such transactions.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

Our property consists primarily of drilling rigs, pressure pumping equipment and related equipment. We own substantially all of the equipment used in our businesses.

Our corporate headquarters is in leased office space and is located at 450 Gears Road, Suite 500, Houston, Texas. Our telephone number at that address is (281) 765-7100. Our primary administrative office, which is located in Snyder, Texas, is owned and includes approximately 37,000 square feet of office and storage space.

Contract Drilling Operations — Our drilling services are supported by several offices and yard facilities located throughout our areas of operations, including Texas, Oklahoma, Colorado, North Dakota, Wyoming, Pennsylvania and western Canada.

Pressure Pumping — Our pressure pumping services are supported by several offices and yard facilities located throughout our areas of operations, including Texas, Pennsylvania, Ohio, West Virginia and Kentucky.

Oil and Natural Gas Working Interests — Our interests in oil and natural gas properties are primarily located in Texas and New Mexico.

We own our administrative offices in Snyder, Texas, as well as several of our other facilities. We also lease a number of facilities, and we do not believe that any one of the leased facilities is individually material to our operations. We believe that our existing facilities are suitable and adequate to meet our needs.

We incorporate by reference in response to this item the information set forth in Item 1 of this Report and the information set forth in Note 3 of the Notes to Consolidated Financial Statements included in Item 8 of this Report.

Item 3. Legal Proceedings.

In May 2013, the U.S. Equal Employment Opportunity Commission ("EEOC") notified us of cause findings related to certain of our employment practices. The cause findings relate to allegations that we tolerated a hostile work environment for employees based on national origin and race. The cause findings also allege, among other things, failure to promote, subjecting employees to adverse employment terms and conditions and retaliation. We and the EEOC engaged in the statutory conciliation process. In March 2014, the EEOC notified us that this matter will be forwarded to its legal unit for litigation review. In November 2014, we and the EEOC participated in a mediation to resolve the matter. Discussions are ongoing. If no resolution is reached, we believe that litigation will ensue, and we intend to defend ourselves vigorously. Based on the information available to us at this time, we do not expect the outcome of this matter to have a material adverse effect on our financial condition, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of this matter.

In October 2014, we were notified by EPA region 6 that it intends to seek civil penalties for alleged RCRA administrative violations at a former facility of one of our subsidiaries in Midland, Texas. The EPA subsequently alleged RCRA administrative violations at other facilities of that subsidiary and are seeking an aggregate monetary penalty of approximately $1.1 million. We are in negotiations with the EPA regarding the scope and amount of any potential settlement. We do not expect the outcome of this matter to have a material adverse effect on our financial condition, results of operations or cash flows.

Other than the matters described above, the Company is party to various other legal proceedings arising in the normal course of its business; the Company does not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on its financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosure.

Not applicable.

PART II

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

(a) Market Information

Our common stock, par value $0.01 per share, is publicly traded on the Nasdaq Global Select Market and is quoted under the symbol "PTEN." Our common stock is included in the S&P MidCap 400 Index and several other market indices. The following table provides high and low sales prices of our common stock for the periods indicated:

	High	Low
2013:		
First quarter	$25.48	$18.59
Second quarter	25.12	18.96
Third quarter	22.41	18.83
Fourth quarter	26.09	21.29
2014:		
First quarter	$31.95	$24.37
Second quarter	35.42	30.24
Third quarter	38.43	31.12
Fourth quarter	33.28	14.01

(b) Holders

As of February 5, 2015, there were approximately 1,300 holders of record of our common stock.

(c) Dividends

We paid cash dividends during the years ended December 31, 2013 and 2014 as follows:

	Per Share	Total (in thousands)
2013:		
Paid on March 29, 2013	$0.05	$ 7,312
Paid on June 28, 2013	0.05	7,361
Paid on September 30, 2013	0.05	7,231
Paid on December 31, 2013	0.05	7,208
Total cash dividends	$0.20	$ 29,112
2014:		
Paid on March 27, 2014	$0.10	$ 14,456
Paid on June 26, 2014	0.10	14,562
Paid on September 24, 2014	0.10	14,634
Paid on December 24, 2014	0.10	14,636
Total cash dividends	$0.40	$ 58,288

On February 4, 2015, our Board of Directors approved a cash dividend on our common stock in the amount of $0.10 per share to be paid on March 25, 2015 to holders of record as of March 11, 2015. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other factors.

(e) Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases of our common stock made by us during the quarter ended December 31, 2014.

Period Covered	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares (or Units) Purchased	Approximate Dollar Value of Shares That May Yet Be Purchased

				as Part of Publicly Announced Plans or Programs	Under the Plans or Programs (in thousands)(1)
October 2014	—	$	—	—	$ 187,016
November 2014	—	$	—	—	$ 187,016
December 2014	—	$	—	—	$ 187,016
Total	—	$	—	—	$ 187,016

(1) On September 9, 2013, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $200 million of our common stock in open market or privately negotiated transactions.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2009 through December 31, 2014, with the cumulative total return of the Standard & Poors 500 Stock Index, the Standard & Poors MidCap Index, the Oilfield Service Index and a peer group determined by us. Our peer group consists of Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Energy Services Corp. and Precision Drilling Corp. All of the companies in our peer group are providers of land-based drilling services. Nabors Industries, Ltd. also is a provider of pressure pumping services. The graph assumes investment of $100 on December 31, 2009 and reinvestment of all dividends.

	Fiscal Year Ended December 31,					
	2009	2010	2011	2012	2013	2014
Company/Index	($)	($)	($)	($)	($)	($)
Patterson-UTI Energy, Inc.	100.00	142.07	132.82	125.36	171.93	114.47
Peer Group Index	100.00	116.37	112.73	99.43	132.93	103.78
S&P 500 Stock Index	100.00	115.06	117.49	136.30	180.44	205.14
Oilfield Service Index	100.00	126.92	113.53	117.14	151.78	116.06
S&P MidCap Index	100.00	126.64	124.45	146.70	195.84	214.97

The foregoing graph is based on historical data and is not necessarily indicative of future performance. This graph shall not be deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulations 14A or 14C under the Exchange Act or to the liabilities of Section 18 under such Act.

Item 6. Selected Financial Data.

Our selected consolidated financial data as of December 31, 2014, 2013, 2012, 2011 and 2010, and for each of the five years in the period ended December 31, 2014 should be read in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the Consolidated Financial Statements and related Notes thereto, included as Items 7 and 8, respectively, of this Report. Due to the sale of our drilling and completion fluids business in January 2010 and the sale of our electric wireline business in January 2011, the results of operations for those businesses have been reclassified and are presented as discontinued operations for all periods presented.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$1,838,830	$1,679,611	$1,821,713	$1,669,581	$1,081,898
Pressure pumping	1,293,265	979,166	841,771	845,803	350,608
Oil and natural gas	50,196	57,257	59,930	50,559	30,425
Total	3,182,291	2,716,034	2,723,414	2,565,943	1,462,931
Operating costs and expenses:					
Contract drilling	1,066,659	968,754	1,075,491	972,778	655,678
Pressure pumping	1,036,310	744,243	580,878	561,398	235,100
Oil and natural gas	13,102	12,909	11,303	9,615	7,020
Depreciation, depletion, amortization and impairment	718,730	597,469	526,614	437,279	333,493
Selling, general and administrative	80,145	73,852	64,473	64,271	53,042
Net gain on asset disposals	(15,781)	(3,384)	(33,806)	(4,999)	(22,812)
Provision for bad debts	—	—	1,100	—	(2,000)
Acquisition-related expenses	—	—	—	—	2,485
Total	2,899,165	2,393,843	2,226,053	2,040,342	1,262,006
Operating income	283,126	322,191	497,361	525,601	200,925
Other expense	(28,843)	(25,750)	(21,688)	(14,883)	(10,171)
Income from continuing operations before income taxes	254,283	296,441	475,673	510,718	190,754
Income tax expense	91,619	108,432	176,196	187,938	72,856
Income from continuing operations	$162,664	$188,009	$299,477	$322,780	$117,898
Income from continuing operations per common share:					
Basic	$1.12	$1.29	$1.96	$2.08	$0.77
Diluted	$1.11	$1.28	$1.96	$2.06	$0.76
Cash dividends per common share	$0.40	$0.20	$0.20	$0.20	$0.20
Weighted average number of common shares outstanding:					
Basic	144,066	144,356	151,144	153,871	152,772

Diluted	145,376	145,303	151,699	155,304	153,276
Balance Sheet Data:					
Total assets	$5,394,011	$4,687,127	$4,556,911	$4,221,901	$3,423,031
Borrowings under line of credit	303,000	—	—	110,000	—
Other long term debt	670,000	682,500	692,500	382,500	392,500
Stockholders' equity	2,905,810	2,755,997	2,640,657	2,516,631	2,187,607
Working capital	340,688	454,373	340,128	346,238	241,445

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

Recent Developments — Oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $105.68 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late

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January 2015 and around $50 per barrel during the first week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing a severe downturn. Market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2015 will be a challenging year for our industry.

We believe the vast majority of exploration and production companies, including our customers, have significantly reduced their 2015 capital spending plans. The initial impact of these spending reductions is evidenced by the published rig counts which have declined more 25% since their recent peak in October 2014.

Our rig count has also declined. During October 2014, the number of our drilling rigs operating in the United States was as high as 214, and as of February 10, 2015 we had 173 drilling rigs operating in the United States. We have received indications of customers' intent to early terminate a number of term contracts and many of our drilling customers are seeking price reductions. We expect the number of our drilling rigs operating in the United States to decline at least another 20% during the next 90 days.

Our pressure pumping business is also beginning to see the effects of reduced spending by customers. Some previously scheduled pressure pumping jobs have been cancelled or deferred and many customers are also seeking price reductions.

In anticipation of this downturn, we began reducing our cost structure in the fourth quarter of 2014. In 2015, we have continued to reduce our cost structure and, to date, we have reduced our drilling headcount at a rate slightly higher than the reduction in our rig count. We have also reduced our capital expenditure plans for 2015. Along with other reductions, we now plan to only build new drilling rigs that are currently committed under term contracts. We plan to continue to adjust our cost structure in line with our level of operating activity.

We expect that our term contract coverage and scalability with respect to labor and other operating costs should position us to weather this downturn. In the event oil prices remain depressed for a sustained period, or decline further, however, we may experience further, significant declines on both drilling activity and spot dayrate pricing, and on pressure pumping activity and pricing, which could have a material adverse effect on our business, financial condition and results of operations.

Management Overview — We are a leading provider of services to the North American oil and natural gas industry. Our services primarily involve the drilling, on a contract basis, of land-based oil and natural gas wells and pressure pumping services. In addition to these services, we also invest, on a non-operating working interest basis, in oil and natural gas properties.

As of December 31, 2014, we had a drilling fleet that consisted of 239 land-based drilling rigs. There continues to be uncertainty with respect to the global economic environment, and oil and natural gas prices are volatile. Oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $105.68 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $50 per barrel during the first week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). In response, many of our customers have announced significant reductions in their 2015 capital spending budgets. During October 2014, the number of our drilling rigs operating in the United States was as high as 214, and as of February 10, 2015 we had 173 drilling rigs operating in the United States. We expect the number of our drilling rigs operating in the United States to continue to decline at least through the first quarter of 2015.

We have addressed our customers' needs for drilling horizontal wells in shale and other unconventional resource plays by expanding our areas of operation and improving the capabilities of our drilling fleet during the last several years. As of December 31, 2014, we have completed 145 new APEX® rigs and made performance and safety improvements to existing high capacity rigs. We have plans to complete 16 additional new APEX® rigs in 2015.

In connection with horizontal shale and other unconventional resource plays, we have added equipment to perform service intensive fracturing jobs. As of December 31, 2014, we had approximately 1.0 million hydraulic horsepower in our pressure pumping fleet. This is a net increase of approximately 866,000 horsepower since the end of 2009. In recent years, low natural gas prices and the industry-wide addition of new pressure pumping equipment to the marketplace led to an excess supply of pressure pumping equipment in North America.

We maintain a backlog of commitments for contract drilling revenues under term contracts, which we define as contracts with a fixed term of six months or more. Our backlog as of December 31, 2014 was approximately $1.5 billion. We expect approximately $953 million of our backlog to be realized in 2015. We generally calculate our backlog by multiplying the dayrate under our term drilling contracts by the number of days remaining under the contract. The calculation does not include any revenues related to other fees such as for mobilization, demobilization and customer reimbursables, nor does it include potential reductions in rates for unscheduled standby or during periods in which the rig is moving, on standby or incurring maintenance and repair time in excess of what is permitted under the drilling contract. In addition, generally our term drilling contracts are subject to termination by the customer on short notice and provide for an early termination payment to us in the event that the contract is terminated by the customer. For contracts for which we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period we expect to receive the lower rate. See “Item 1A. Risk Factors – Our Current Backlog of Contract Drilling Revenue May Not Ultimately Be Realized as Fixed-Term Contracts May in Certain Instances Be Terminated Without an Early Termination Payment.”

For the three years ended December 31, 2014, our operating revenues consisted of the following (dollars in thousands):

	2014		2013		2012	
Contract drilling	$1,838,830	58 %	$1,679,611	62 %	$1,821,713	67 %
Pressure pumping	1,293,265	41 %	979,166	36 %	841,771	31 %
Oil and natural gas	50,196	1 %	57,257	2 %	59,930	2 %
	$3,182,291	100%	$2,716,034	100%	$2,723,414	100%

Generally, the profitability of our business is impacted most by two primary factors in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During 2014, our average number of rigs operating was 203 in the United States and 8 in Canada compared to 184 in the United States and 8 in Canada in 2013 and 214 in the United States and 7 in Canada in 2012. Our average revenue per operating day was $23,880 in 2014 compared to $24,020 in 2013 and $22,540 in 2012. We had consolidated net income of $163 million for 2014 compared to $188 million for 2013. This decrease in consolidated net income was due to a charge of $77.9 million related to the retirement of 55 mechanical drilling rigs and the write-off of excess spare components for the now reduced size of our mechanical rig fleet. Also, revenues in 2013 included early termination revenues totaling approximately $65.2 million related to early contract terminations.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our services. Conversely, in periods when these commodity prices deteriorate, the demand for our services generally weakens and we experience downward pressure on pricing for our services. Oil and natural gas prices and our monthly average number of rigs operating have declined from recent highs. In December 2014, our average number of rigs operating was 208 in the United States and 8 in Canada. In January 2015, our average number of rigs operating decreased to 198.

We are also highly impacted by operational risks, competition, the availability of excess equipment, labor issues and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations. Please see “Risk Factors” in Item 1A of this Report.

Critical Accounting Policies

In addition to established accounting policies, our consolidated financial statements are impacted by certain estimates and assumptions made by management. The following is a discussion of our critical accounting policies pertaining to property and equipment, goodwill, revenue recognition, the use of estimates and oil and natural gas properties.

Property and equipment — Property and equipment, including betterments which extend the useful life of the asset, are stated at cost. Maintenance and repairs are charged to expense when incurred. We provide for the depreciation of our property and equipment using the straight-line method over the estimated useful lives. Our method of depreciation does not change when equipment becomes idle; we continue to depreciate idled equipment on a straight-line basis. No provision for salvage value is considered in determining depreciation of our property and equipment. We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances (“triggering events”) indicate that the carrying values of certain assets may not be recovered over their estimated remaining useful lives. In connection with this review, assets are grouped at the lowest level at which identifiable cash flows are largely independent of other asset groupings. The cyclical nature of our industry has resulted in fluctuations in rig utilization over periods of time. Management believes that the contract drilling industry will continue to be cyclical and rig utilization will continue to fluctuate. Based on management’s expectations of future trends, we estimate future cash flows over the life of the respective assets or asset groupings in our assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as management’s expectations regarding the continuation of these trends in the future. Provisions for asset impairment are charged against income when estimated future cash flows, on an undiscounted basis, are less than the asset’s net book value. Any provision for impairment is measured at fair value.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type (such as drilling conventional vertical wells versus drilling longer horizontal wells using high capacity rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to our other marketed rigs are transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs are retired. In 2014, we identified 55 mechanical rigs that we determined would no longer be marketed. We recorded a charge of $77.9 million related to the retirement of these mechanical rigs and the write-off of excess spare components for the now reduced size of our mechanical fleet. In 2013, we identified 48 rigs that would no longer be marketed. Also, we had 55 additional mechanical rigs that were not operating. Although these 55 rigs remained marketable at the time, we had lower expectations with respect to utilization of these rigs due to the industry shift to electric powered drilling rigs. We recorded a charge of $37.8 million related to the retirement of the 48 rigs and the 55 mechanical rigs that remained marketable but were not operating. In 2012, we identified 36 rigs that it determined would no longer be marketed and recorded a charge of $5.2 million related to the retirement of these rigs.

We also evaluate our fleet of marketable pressure pumping equipment and in 2012 identified approximately 37,000 horsepower of pressure pumping equipment that would be retired. The net book value of these assets of $7.3 million was expensed in our consolidated statements of operations. There were no similar charges in 2014 or 2013.

In light of the significant decline in oil and natural gas commodity prices beginning in the fourth quarter of 2014 and continuing into 2015, we deemed it necessary to assess the recoverability of long-lived assets within our contract drilling and pressure pumping segments. With respect to these assets, we estimated future cash flows over the expected life of the assets, and determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets. Based on this assessment, no impairment was indicated. Impairment considerations related to our oil and natural gas segment are discussed below.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. We evaluate goodwill at least annually on December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. Our reporting units for impairment testing have been determined to be the same as our operating segments. We currently have goodwill in our contract drilling and pressure pumping operating segments. We first determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying value after considering qualitative, market and other factors. If so, then goodwill impairment is determined using a two-step impairment test. From time to time, we may perform the first step of quantitative testing for goodwill impairment in lieu of performing a qualitative assessment. The first step is to compare the fair value of an entity’s reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeds its fair value, the second step of the impairment test is performed whereby the fair value of the reporting unit is allocated to its identifiable tangible and intangible assets and liabilities with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized in the amount of the shortfall.

We performed a quantitative impairment assessment of our goodwill as of December 31, 2013. In completing the first step of the analysis, we used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of the reporting units. In developing this fair value estimate, we applied key assumptions including an assumed discount rate of 11.87% for the contract drilling reporting unit and an assumed discount rate of 12.40% for the pressure pumping reporting unit. An assumed long-term growth rate of 3.00% was used for both reporting units. Based on the results of the first step of the impairment test in 2013, we concluded that no impairment was indicated in our contract drilling or pressure pumping reporting units, as the estimated fair value of each reporting unit exceeded its carrying value.

In connection with our annual goodwill impairment assessment as of December 31, 2014, we determined based on an assessment of qualitative factors that it was more likely than not that the fair values of our reporting units were greater than their carrying amounts and further testing was not necessary. In making this determination, we considered the continued demand experienced during 2014 for our services in the contract drilling and pressure pumping businesses. We also considered the current and expected levels of commodity prices for oil and natural gas, which influence the overall level of business activity in these operating segments. Additionally, operating results for 2014 and forecasted operating results for 2015 were also taken into account. Our overall market capitalization and the large amount of calculated excess of the fair values of our reporting units over their carrying values from our 2013 quantitative Step 1 assessment of goodwill were also considered.

We have undertaken extensive efforts in the past several years to upgrade our fleet of equipment and believe that we are well positioned from a competitive standpoint to satisfy demand for high technology drilling of unconventional horizontal wells, which should help mitigate decreases in demand for drilling conventional vertical wells. In the event that market conditions were to remain weak for a protracted period, we may be required to record an impairment of goodwill in our contract drilling or pressure pumping reporting units in the future, and such impairment could be material.

Revenue recognition — Revenues from daywork drilling and pressure pumping activities are recognized as services are performed. Expenditures reimbursed by customers are recognized as revenue and the related expenses are recognized as direct costs. All of the wells we drilled in 2014, 2013 and 2012 were drilled under daywork contracts.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Key estimates used by management include:

- allowance for doubtful accounts,
- depreciation, depletion and amortization,
- fair values of assets acquired and liabilities assumed in acquisitions,
- goodwill and long-lived asset impairments, and
- reserves for self-insured levels of insurance coverage.

Oil and natural gas properties — Working interests in oil and natural gas properties are accounted for using the successful efforts method of accounting. Under the successful efforts method of accounting, exploration costs which result in the discovery of oil and natural gas reserves and all development costs are capitalized to the appropriate well. Exploration costs which do not result in discovering oil and natural gas reserves are charged to expense when such determination is made. Costs of exploratory wells are initially capitalized to wells-in-progress until the outcome of the drilling is known. We review wells-in-progress quarterly to determine whether sufficient progress is being made in assessing the reserves and economic viability of the respective projects. If no progress has been made in assessing the reserves and economic viability of a project after one year following the completion of drilling, we consider the well costs to be impaired and recognize the costs as expense. Geological and geophysical costs, including seismic costs and costs to carry and retain undeveloped properties, are charged to expense when incurred. The capitalized costs of both developmental and successful exploratory type wells, consisting of lease and well equipment and intangible development costs, are depreciated, depleted and amortized using the units-of-production method, based on engineering estimates of total proved developed oil and natural gas reserves for each respective field. Oil and natural gas leasehold acquisition costs are depreciated, depleted and amortized using the units-of-production method, based on engineering estimates of total proved oil and natural gas reserves for each respective field.

We review our proved oil and natural gas properties for impairment whenever a triggering event occurs, such as downward revisions in reserve estimates or decreases in expected future oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared based on our expectation of future pricing over the lives of the respective fields. These cash flow estimates are reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between net book value and fair value. The fair value estimates used in measuring impairment are based on internally developed unobservable inputs including reserve volumes and future production, pricing and operating costs (level 3 inputs in the fair value hierarchy of fair value accounting). The expected future net cash flows are discounted using an annual rate of 10% to determine fair value. We review unproved oil and natural gas properties quarterly to assess potential impairment. Our impairment assessment is made on a lease-by-lease basis and considers factors such as our intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed. Impairment expense related to proved and unproved oil and natural gas properties totaled approximately $20.9 million, $4.0 million and $1.9 million for the years ended December 31, 2014, 2013 and 2012, respectively, and is included in depreciation, depletion, amortization and impairment in the consolidated statements of operations.

For additional information on our accounting policies, see Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Liquidity and Capital Resources

Our liquidity as of December 31, 2014 included approximately $341 million in working capital and approximately $157 million available under our $500 million revolving credit facility. Subsequent to December 31, 2014, we received an $82 million federal income tax refund related to 2014. The refund, along with other cash generated from our cash management efforts, were used to repay $103 million outstanding under our revolving credit facility during 2015. As of February 10, 2015, availability under the revolving credit facility was $260 million. In an attempt to further increase availability under our revolving credit facility, we are working with a lender to move $39.8 million of letters of credit currently outstanding under our revolving credit facility into a new separate facility to be used only for letters of credit.

We believe our current liquidity together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to build new equipment, make improvements to our existing equipment, service our debt and pay cash dividends. If under current market conditions we desire to pursue opportunities for growth that require capital, we believe we would likely require additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

As of December 31, 2014, we had working capital of $341 million, including cash and cash equivalents of $43 million, compared to working capital of $454 million and cash and cash equivalents of $250 million at December 31, 2013.

During 2014, our sources of cash flow included:

- $729 million from operating activities,
- $303 million in net borrowings under our revolving credit facility,
- $39.6 million from the exercise of stock options and related tax benefits associated with stock-based compensation, and
- $33.2 million in proceeds from the disposal of property and equipment.

During 2014, we used $176 million to acquire pressure pumping operations, $58.3 million to pay dividends on our common stock, $13.6 million to repurchase shares of our common stock, $10.0 million to repay long-term debt and $1.1 billion:

- to build new drilling rigs and pressure pumping equipment,
- to make capital expenditures for the betterment and refurbishment of our drilling rigs and pressure pumping equipment,
- to acquire and procure equipment and facilities for our drilling and pressure pumping operations, and
- to fund investments in oil and natural gas properties on a working interest basis.

We paid cash dividends during the year ended December 31, 2014 as follows:

	Per Share	Total (in thousands)
Paid on March 27, 2014	$ 0.10	$ 14,456
Paid on June 26, 2014	0.10	14,562
Paid on September 24, 2014	0.10	14,634
Paid on December 24, 2014	0.10	14,636
Total cash dividends	$ 0.40	$ 58,288

On February 4, 2015, our Board of Directors approved a cash dividend on our common stock in the amount of $0.10 per share to be paid on March 25, 2015 to holders of record as of March 11, 2015. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other factors.

On August 1, 2007, our Board of Directors approved a stock buyback program authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions. On July 25, 2012, our Board of Directors terminated the remaining authority under the 2007 stock buyback program, and approved a new stock buyback program authorizing purchases of up to $150 million of our common stock in open market or privately negotiated transactions. On September 6, 2013, the Company's Board of Directors terminated any remaining authority under the 2012 stock buyback program, and approved a new stock buyback program that authorizes purchase of up to

$200 million of the Company's common stock in open market or privately negotiated transactions. As of December 31, 2014, we had remaining authorization to purchase approximately $187 million of our outstanding common stock under the new stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

We acquired shares of stock from employees during 2014, 2013 and 2012 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price in connection with the exercise of stock options by employees. The remainder of these shares was acquired to satisfy payroll tax withholding obligations upon the exercise of stock options, the settlement of performance unit awards and the vesting of restricted stock. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan") or the Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan") and not pursuant to the stock buyback program.

Treasury stock acquisitions during the year ended December 31, 2014, 2013 and 2012 were as follows (dollars in thousands):

	2014		2013		2012	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	42,268,057	$880,888	38,146,738	$795,051	27,487,571	$624,759
Purchases pursuant to stock buyback programs:						
2007 program	—	—	—	—	4,708,784	70,092
2012 program	—	—	2,567,266	51,107	5,863,451	98,892
2013 program	13,898	466	602,564	12,517	—	—
Acquisitions pursuant to long-term incentive plans	536,630	17,681	951,489	22,213	86,932	1,308
Treasury shares at end of period	42,818,585	$899,035	42,268,057	$880,888	38,146,738	$795,051

On September 27, 2012, we entered into a credit agreement (the "Credit Agreement"). The Credit Agreement is a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility. The Credit Agreement replaced a previous senior unsecured revolving credit facility.

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time. The revolving credit facility contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million, in each case outstanding at any time.

The term loan facility provides for a loan of $100 million, which was drawn on December 24, 2012. The term loan facility is payable in quarterly principal installments which commenced December 27, 2012. The installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the subsequent four quarterly installments and 13.75% of the original principal amount for the final four quarterly installments.

Subject to customary conditions, we may request that the lenders' aggregate commitments with respect to the revolving credit facility and/or the term loan facility be increased by up to $100 million, not to exceed total commitments of $700 million. The maturity date under the Credit Agreement is September 27, 2017 for both the revolving facility and the term facility.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. The applicable margin on LIBOR rate loans varies from 2.25% to 3.25% and the applicable margin on base rate loans varies from 1.25% to 2.25%, in each case determined based upon our debt to capitalization ratio. As of December 31, 2014, the applicable margin on LIBOR rate loans was 2.25% and the applicable margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at December 31, 2014, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2015. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

Each of our U.S. subsidiaries, other than one domestic holding company and certain immaterial subsidiaries, has unconditionally guaranteed all existing and future indebtedness and liabilities of the other guarantors and us arising under the Credit Agreement and other loan documents. Such guarantees also cover obligations of us and any of our subsidiaries arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization (“EBITDA”) of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2014. The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require us to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy such acceleration is automatic), and (iii) require us to cash collateralize any outstanding letters of credit.

As of December 31, 2014, we had $82.5 million principal amount outstanding under the term loan facility at an interest rate of 2.50% and $303 million outstanding under the revolving credit facility at a weighted interest rate of 2.65%. We had $39.8 million in letters of credit outstanding at December 31, 2014 and, as a result, had available borrowing capacity of approximately $157 million at that date.

On October 5, 2010, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.97% Series A Senior Notes due October 5, 2020 (the "Series A Notes") in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. We will pay interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amounts of our 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. We will pay interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are our senior unsecured obligations, which rank equally in right of payment with all of our other unsubordinated indebtedness. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of our existing domestic subsidiaries other than immaterial subsidiaries.

The Series A Notes and Series B Notes are prepayable at our option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements. We must offer to prepay the notes upon the occurrence of any change of control. In addition, we must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2014. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if the Company defaults in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

Commitments and Contingencies — As of December 31, 2014, we maintained letters of credit in the aggregate amount of $39.8 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of December 31, 2014, no amounts had been drawn under the letters of credit.

As of December 31, 2014, we had commitments to purchase approximately $512 million of major equipment for our drilling and pressure pumping businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2016, 2017 and 2018. As of December 31, 2014, the remaining obligation under these agreements was approximately $71.8 million, of which materials with a total purchase price of approximately $15.4 million were required to be purchased during 2015. In the event that the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, our pressure pumping business entered into an agreement with a proppant vendor to advance up to $12.0 million to such vendor to finance its construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of December 31, 2014, advances of approximately $11.8 million had been made under this agreement and repayments of approximately $8.6 million had been received resulting in a balance outstanding of approximately $3.2 million.

In May 2013, the EEOC notified us of cause findings related to certain of our employment practices. The cause findings relate to allegations that we tolerated a hostile work environment for employees based on national origin and race. The cause findings also allege, among other things, failure to promote, subjecting employees to adverse employment terms and conditions and retaliation. We and the EEOC engaged in the statutory conciliation process. In March 2014, the EEOC notified us that this matter will be forwarded to its legal unit for litigation review. In November 2014, we and the EEOC participated in a mediation to resolve the matter. Discussions are ongoing. If no resolution is reached, we believe that litigation will ensue, and we intend to defend ourselves vigorously. Based on the information available to us at this time, we do not expect the outcome of this matter to have a material adverse effect on our financial condition, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of this matter.

In October 2014, we were notified by EPA Region 6 that it intends to seek civil penalties for alleged RCRA violations at a former facility on one of our subsidiaries in Midland, Texas. The EPA subsequently alleged RCRA violations at other facilities of that subsidiary and are seeking an aggregate monetary penalty of approximately $1.1 million. We are in negotiations with the EPA regarding the scope and amount of any potential settlement. We do not expect the outcome of this matter to have a material adverse effect on our financial condition, results of operations or cash flows.

Trading and Investing — We have not engaged in trading activities that include high-risk securities, such as derivatives and non-exchange traded contracts. We invest cash primarily in highly liquid, short-term investments such as overnight deposits and money market accounts.

Contractual Obligations

The following table presents information with respect to our contractual obligations as of December 31, 2014 (dollars in thousands):

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Term loan (1)	$82,500	$12,500	$70,000	$—	$—
Interest on term loan (2)	4,082	1,992	2,090	—	—
Revolving credit (3)	303,000	—	303,000	—	—
Interest on revolving credit (4)	22,280	8,132	14,148	—	—
Series A Notes (5)	300,000	—	—	—	300,000
Interest on Series A Notes (6)	85,940	14,910	29,820	29,820	11,390
Series B Notes (7)	300,000	—	—	—	300,000
Interest on Series B Notes (8)	95,506	12,810	25,620	25,620	31,456
Leases (9)	34,882	14,554	12,269	4,472	3,587
Equipment purchases (10)	511,819	511,819	—	—	—
Inventory purchases (11)	71,774	15,441	39,833	16,500	—
	$1,811,783	$592,158	$496,780	$76,412	$646,433

(1) Represents repayments of borrowings under the term loan portion of the Credit Agreement. The term loan matures on September 27, 2017.

(2) Interest to be paid on term loan using 2.50% rate in effect as of December 31, 2014.

(3) Represents repayments of borrowings under the revolving credit portion of the Credit Agreement. The revolving credit matures on September 27, 2017.

(4) Interest to be paid on revolving credit using the weighted interest rate of 2.65% in effect as of December 31, 2014.

(5) Principal repayment of the Series A Notes is required at maturity on October 5, 2020.

(6) Interest to be paid on the Series A Notes using 4.97% coupon rate.

(7) Principal repayment of the Series B Notes is required at maturity on June 14, 2022

(8) Interest to be paid on the Series B Notes using 4.27% coupon rate.

(9) See Note 11 of Notes to Consolidated Financial Statements.

(10) Represents commitments to purchase major equipment to be delivered in 2015 based on expected delivery dates.

(11) Represents commitments to purchase proppants and chemicals for our pressure pumping business.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2014.

Results of Operations

Comparison of the years ended December 31, 2014 and 2013

The following tables summarize operations by business segment for the years ended December 31, 2014 and 2013:

Contract Drilling	Year Ended December 31, 2014	2013	% Change
	(Dollars in thousands)		
Revenues	$1,838,830	$1,679,611	9.5 %
Direct operating costs	1,066,659	968,754	10.1 %
Margin (1)	772,171	710,857	8.6 %
Selling, general and administrative	6,297	5,867	7.3 %
Depreciation, amortization and impairment	524,023	438,728	19.4 %
Operating income	$241,851	$266,262	(9.2)%
Operating days	77,000	69,918	10.1 %
Average revenue per operating day	$23.88	$24.02	(0.6)%
Average direct operating costs per operating day	$13.85	$13.86	(0.1)%
Average margin per operating day (1)	$10.03	$10.17	(1.4)%
Average rigs operating	211.0	191.6	10.1 %
Capital expenditures	$771,593	$504,508	52.9 %

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The demand for our contract drilling services is impacted by the market price of oil and natural gas. The reactivation and construction of new land drilling rigs in the United States in recent years has contributed to an excess capacity of land drilling rigs compared to demand. Also in recent years, customer demand has shifted away from mechanically powered drilling rigs to electric powered drilling rigs, reducing the utilization rates of our mechanically powered drilling rigs. The average market price of oil and natural gas for each of the fiscal quarters and full year in 2014 and 2013 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2013:					
Average oil price per Bbl (1)	$94.34	$94.10	$105.84	$97.34	$97.91
Average natural gas price per Mcf (2)	$3.49	$4.01	$3.55	$3.85	$3.73
2014:					
Average oil price per Bbl (1)	$98.75	$103.35	$97.78	$73.16	$93.26
Average natural gas price per Mcf (2)	$5.21	$4.61	$3.96	$3.80	$4.39

(1)

The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.

(2) The average natural gas price represents the average monthly Henry Hub Spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs increased in 2014 compared to 2013 as a result of an increase in the number of rigs operating. Revenues in 2013 included approximately $65.2 million of early termination revenues. Average revenue per operating day and average margin per operating day were higher in 2013 due to the early termination revenue. Capital expenditures were incurred in 2014 and 2013 to build new drilling rigs, to modify and upgrade existing drilling rigs and to acquire additional equipment including top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. In 2014, we identified 55 mechanical rigs that we determined would no longer be marketed. We recorded additional depreciation, amortization and impairment expense of $77.9 million related to the retirement of these mechanical rigs and the write-off of excess spare components for the now reduced size of our mechanical fleet. In 2013, we identified 48 rigs that would no longer be marketed. Also, we had 55 additional mechanical rigs that were not operating. Although these 55 rigs remained marketable at the time, we had lower expectations with respect to utilization of these rigs due to the industry shift to electric powered drilling rigs. We recorded a charge of $37.8 million related to the retirement of the 48 rigs and the 55 mechanical rigs that remained marketable but were not operating. Significant capital expenditures incurred in recent years to add new rig capacity also contributed to the increase in depreciation expense.

Pressure Pumping	Year Ended December 31, 2014	2013	% Change
	(Dollars in thousands)		
Revenues	$1,293,265	$979,166	32.1 %
Direct operating costs	1,036,310	744,243	39.2 %
Margin (1)	256,955	234,923	9.4 %
Selling, general and administrative	20,279	17,695	14.6 %
Depreciation, amortization and impairment	147,595	129,984	13.5 %
Operating income	$89,081	$87,244	2.1 %
Fracturing jobs	1,224	1,261	(2.9)%
Other jobs	4,253	4,800	(11.4)%
Total jobs	5,477	6,061	(9.6)%
Average revenue per fracturing job	$991.89	$705.57	40.6 %
Average revenue per other job	$18.62	$18.63	(0.1)%
Average revenue per total job	$236.13	$161.55	46.2 %
Average direct operating costs per total job	$189.21		